OAH 5-2500-34078
MPUC E-015/GR-16-664

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in the State of Minnesota

FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS

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INTRODUCTION

This matter came before Administrative Law Judge Jim Mortenson pursuant to a Notice and Order for Hearing filed on December 30, 2016. On November 2, 2016, Minnesota Power (Applicant) filed a general rate case seeking an annual rate increase of $55,123,680, or approximately 9.1 percent. On February 28, 2017, Applicant reduced its annual rate increase request to $38,769,070, or approximately 6.1 percent. On July 21, 2017, Applicant increased its annual rate increase request to $49,194,824, or approximately 8 percent.

Public hearings were held in Eveleth, Duluth, Grand Rapids, and Little Falls, Minnesota from June 19 through 22, 2017. Written public comments were received until July 3, 2017.

An evidentiary hearing was held on August 8 through 11, 2017, at the Public Utilities Commission in Saint Paul, Minnesota.

Post-hearing initial briefs were filed by the parties on September 12, 2017. Reply briefs were filed on September 28, 2017, and the record closed.

APPEARANCES

David R. Moeller, in-house counsel, and Elizabeth M. Brama, Valerie T. Herring, and Kodi J. Verhalen, Briggs & Morgan, P.A., represent Minnesota Power (Applicant).

Andrew Moratzka and Sara Johnson-Phillips, Stoel Rives, L.L.P., represent the Large Power Intervenors (LPI).

Pam Marshall appeared on behalf of Energy CENTS Coalition (ECC).[1]

[1] Ms. Marshall is not an attorney. Although the Administrative Law Judge is following a practice by the Office of Administrative Hearings to permit a non-attorney to represent an entity in a case referred by the PUC, it is not the Administrative Law Judge's position that he has the authority to permit the practice of law by a non-attorney on behalf of an entity. *See* Minn. R. 1400.5800 (2017); *see generally Nicollet Restoration, Inc. v. Turnham*, 486 N.W.2d 753 (Minn. 1992); *Hinckley Square Associates v. Cervene*, 871 N.W.2d 426 (Minn. Ct. App. 2015).

Leigh Currie, Kevin Reuther, and Hudson Kingston, Minnesota Center for Environmental Advocacy, represent the Clean Energy Organizations (CEO).

Allen Jenkins, Jenkins at Law, L.L.C., represents Sam's West, Inc. and WAL-MART STORES, Inc. (Wal-Mart).

R. Cameron Winton, Director of Energy and Labor Management Policy, represents the Minnesota Chamber of Commerce (MCC).

Seth J. Bichler, Staff Attorney, and Philip R. Mahowald, The Jacobson Law Group, represent the Fond du Lac Band of Lake Superior Chippewa (FDL).

Kristin Munsch, Deputy Director, represents the Citizens Utility Board (CUB).

John B. Coffman, John B. Coffman, L.L.C., represents AARP.

Ian Dobson and Ryan Barlow, Assistant Attorneys General, represent the Office of the Attorney General – Antitrust and Utilities Division (OAG).

Peter E. Madsen, Linda S. Jensen, and Julia E. Anderson, Assistant Attorneys General, represent the Minnesota Department of Commerce, Division of Energy Resources (the Department).

Clark Kaml and Sundra Bender appeared on behalf of the Public Utilities Commission (the PUC) and asked questions at the evidentiary hearing.

THE PARTIES

Applicant is a public utility in northern Minnesota providing electricity to 145,000 residential and commercial customers, 16 municipalities, and some of the nation's largest industrial customers. Applicant is an operating division of ALLETE, Inc. Applicant represents approximately 77 percent of ALLETE's capital. Over 60 percent of Applicant's retail revenue comes from industrial customers.

LPI consists of 13 large industrial customers of Applicant, including: ArcelorMittal USA (Minorca Mine); Blandin Paper Company; Boise Paper, a Packaging Corporation of America company, formerly known as Boise, Inc.; Enbridge Energy, Limited Partnership; Gerdau Ameristeel US Inc.; Hibbing Taconite Company; Mesabi Nugget Delaware, L.L.C.; PolyMet Mining, Inc.; Sappi Cloquet, L.L.C.; USG Interiors, L.L.C.; United States Steel Corporation (Keetac and Minntac Mines); United Taconite, L.L.C.; and Verso Corporation.

ECC is a non-profit member organization located in St. Paul, Minnesota. ECC promotes affordable utility service for people with low and fixed income to ensure energy is available to everyone. ECC encourages people with low and fixed income to participate in energy issues and energy-related decision-making.

CEO is a group of four environmental advocacy organizations: Fresh Energy, Sierra Club, Wind on the Wires (WOW), and Minnesota Center for Environmental Advocacy (MCEA). Fresh Energy is an independent energy policy non-profit that is working on the transition to a clean energy economy. Sierra Club is a national non-profit environmental organization with over 620,000 members nationwide and nearly 15,000 members in Minnesota. Sierra Club works to protect and promote safe and healthy communities, protect and improve air and water quality in the United States, limit the adverse effects of climate change, and promote clean energy. WOW is a policy organization focused on prioritizing the delivery of large amounts of all types of wind energy to markets in the Upper Midwest. WOW represents members who produce wind power and technology. MCEA is a non-profit environmental organization that works to protect Minnesota's wildlife, natural resources and the health of its people. One of MCEA's five program areas is an Energy Program to advance the pursuit of environmentally sustainable energy policies.

Wal-Mart is a group of commercial customers that operate retail facilities and distribution centers in Applicant's service area.

MCC is a business association of more than 2,300 small and large businesses across Minnesota.

FDL is a sovereign nation with a reservation in St. Louis and Carlton Counties. Approximately 1,800 of FDL's members live on or near the reservation and many are customers of Applicant. Additionally, FDL's government and its enterprises are large consumers of electricity supplied by Applicant.

CUB is a non-profit organization focused on representing the interests of residential and small business utility customers in Minnesota. CUB advocates for affordable and reliable utility service and clean energy. CUB's work includes examining the effects of proposed changes in rates and rate design. CUB also advocates for the modernization of electric grid infrastructure, including the deployment of new utility infrastructure such as advanced metering infrastructure.

AARP is a nationwide non-profit organization that, among many other things, advocates for affordable utilities for people who are aged 50 and over.

OAG is an intervenor in proceedings before the PUC as a matter of right, pursuant to Minn. R. 7929.0800, subp. 3 (2017).

The Department is an intervenor in proceedings before the PUC as a matter of right, pursuant to Minn. Stat. § 216C.09(b) (2016).

STATEMENT OF THE ISSUES

1. Is the test year revenue increase sought by Applicant reasonable, or will it result in unreasonable and excessive earnings?

2. Is Applicant's proposed capital structure and return on equity reasonable?

3. Is the rate design proposed by Applicant reasonable?

4. What is the effect on expected revenue from industrial customers of standard tariffs, electric service agreements (ESAs), and the Energy-Intensive, Trade-Exposed (EITE) credit?

SUMMARY OF RECOMMENDATIONS

1. The test year revenue should be recalculated by Applicant based on the findings, conclusions, and reasons described in this report.

2. Applicant's proposed capital structure and return on equity may not be reasonable. The capital structure and return on equity should be recalculated based on the findings, conclusions, and recommendations in this report.

3. The rate design proposed by Applicant is not reasonable, with exceptions. The current rate design should not change, with exceptions described in this report.

4. Expected revenue from industrial customers will not be significantly changed from standard tariffs, ESAs, and the EITE credit. The rate design recommendations in this report support the goal of the EITE credit.

Based on the evidence in the record and all the proceedings in this matter, the Administrative Law Judge makes the following:

FINDINGS OF FACT[2]

I. PROCEDURAL HISTORY

1. On November 2, 2016, Applicant filed an application (Application) with the PUC for authority to increase general electric rates to its retail customers by $55,123.680, or 9.1 percent, effective January 1, 2017.[3] Applicant also requested an interim rate increase of $48,632,259, or 8 percent, effective January 1, 2017.[4]

2. The Application includes information required by statutes, prior litigation, and PUC orders.[5]

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[2] The court reporter filed a master exhibit list on November 6, 2017. *See* eDocket No. 201711-137173-01. The master exhibit list contains all evidence received into the record during this proceeding.
[3] Exhibit (Ex.) 3, Summary of Filing (Initial Filing Vol. 1).
[4] *Id.* The amount was eventually adjusted to $38.8 million, a 6.1 percent increase. *See* Ex. 25 (Minnesota Power Issues Matrix).
[5] Ex. 3, Notice of Change in Rates at 3-4 (Initial Filing Vol. 1).

3. The Application also includes general rate schedules and tariffs, testimony from several witnesses including expert opinions, and notice proposals for all customers.[6] Applicant proposes to roll $95 million of current revenue through separate billing line items into the base rates.[7] Applicant also proposes to change its rate design and terms of service.[8]

4. On November 4, 2016, the PUC issued a Notice of Comment Period on Completeness and Procedures, soliciting comments on the completeness of Applicant's petition and procedure for moving forward.[9] The initial comment period closed on November 14, 2016, and the reply comment period closed on November 21, 2016.[10]

5. On December 12, 2016, Applicant advised the PUC that it was seeking a lower interim rate increase of $34,732,113, or 5.6 percent, due to increases in production expected by some of Applicant's industrial customers.[11]

6. On December 15, 2016, the PUC met to consider rate increase change and a previously filed Petition by Minnesota Power for Approval of the Amended and Restated Electric Service Agreement (ESA) between United States Steel Corporation and Minnesota Power.[12]

7. On December 29, 2016, the PUC approved the new ESA with the exception of a trade secret provision concerning minimum firm demand (take-or-pay).[13] The trade secret provision was combined with the present matter and Applicant was required to provide supplemental testimony addressing the specifics of the take-or-pay provisions in the ESA and the associated benefits and cost recovery.[14]

8. On December 30, 2016, the PUC accepted Applicant's petition as complete, set interim rates, extended the timeline, and referred the petition to the Office of Administrative Hearings for contested case proceedings on the issues described above.[15] At the time the case was referred, the existing parties were Applicant, the Department, OAG, and LPI.[16]

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[6] *Id.* at 3-5.
[7] Ex. 25 (Minnesota Power Issues Matrix).
[8] Ex. 3, Summary of Filing (Initial Filing Vol. 1).
[9] Notice of Comment Period on Completeness and Procedures (Nov. 4, 2016) (eDocket No. 201611-126296-01).
[10] *Id.*
[11] Request to Modify Interim Rate Proposal (Dec. 12, 2016) (eDocket No. 201612-127211-01).
[12] *In re Pet. by Minn. Power for Approval of an Am. and Restated Elec. Serv. Agreement between U.S. Steel Corp. and Minn. Power*, MPUC Docket No. E-015/M-16-836, Order Approving In Part Proposed Electric Service Agreement, Referring Matter to Rate Case, and Closing Docket (Dec. 29, 2016) (eDocket No. 201612-127667-02).
[13] *Id.* at 3-4.
[14] *Id.* at 4-5.
[15] Notice and Order for Hearing (Dec. 30, 2016) (eDocket No. 201612-127717-01); Order Accepting Filing, Extending Timeline, and Suspending Rates (Dec. 30, 2016) (eDocket No. 201612-127719-01); Order Setting Interim Rates (Dec. 30, 2016) (eDocket No. 201612-127718-01).
[16] Notice and Order for Hearing at 4 (Dec. 30, 2016) (eDocket No. 201612-127717-01).

9. A prehearing conference was held on January 17, 2017, at the PUC's office in Saint Paul.[17] On January 24, 2017, the Administrative Law Judge issued scheduling and protective orders.[18]

10. On January 25, 2017, the Administrative Law Judge granted intervention to ECC, Wal-Mart, and CEO.[19] On January 26, 2017, the Administrative Law Judge granted intervention to MCC.[20] On March 9, 2017, the Administrative Law Judge granted intervention to FDL.[21] On April 26, 2017, the Administrative Law Judge granted limited intervention to AARP.[22] On May 12, 2017, the Administrative Law Judge granted limited intervention to CUB.[23]

11. On February 28, 2017, Applicant filed supplemental direct testimony.[24] Applicant reduced its revenue deficiency to $38,769,070, or a 6.1 percent increase.[25]

12. On May 31, 2017, the intervening parties filed direct testimony.

13. On June 12, 2017, each of the parties filed an issues matrix.

14. Public hearings were held in Eveleth, Duluth, Grand Rapids, and Little Falls from June 19-22, 2017.[26]

15. On June 29, 2017, the parties filed rebuttal testimony.

16. On July 21, 2017, the parties filed surrebuttal testimony. Applicant asserted its final proposed revenue deficiency (rate increase) is $49,194,824, or an 8 percent increase.[27]

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[17] Prehearing Transcript (Tr.) (Jan. 18, 2017) (eDocket No. 20172-128931-01).
[18] First Prehearing Order (Jan. 24, 2017) (eDocket No. 20171-0128415091); Protective Order (Jan. 24, 2017) (eDocket No. 20171-128398-01).
[19] Order Granting Petition to Intervene by ECC (Jan. 25, 2017) (eDocket No. 20171-128492-03); Order Granting Petition to Intervene by Wal-Mart (Jan. 25, 2017) (eDocket No. 20171-128492-02); Order Granting Petition to Intervene by CEOS (Jan. 25, 2017) (eDocket No. 20171-0128492-01).
[20] Order Granting Petition to Intervene by MCC (Jan. 26, 2017) (eDocket No. 20171-128503-01).
[21] Order Granting Petition to Intervene by FDL (Mar. 9, 2017) (eDocket No. 20173-129763-01).
[22] Order Granting Petition to Intervene by AARP Limited to Specific Issue (Apr. 26, 2017) (eDocket No. 20174-131268-01).
[23] Order Granting Petition for Limited Intervention by CUB (May 12, 2017) (eDocket No. 20175-131811-01).
[24] Ex. 69 (Pierce Supplemental Direct); Ex. 80 (Shimmin Supplemental Direct); Ex. 84 (Podratz Supplemental Direct).
[25] Ex. 84 at 13, 15, MAP-SD-1 (Podratz Supplemental Direct).
[26] Eveleth 2:00 p.m. Public Hearing Tr. (June 19, 2017) (eDocket No. 20177-134054-01); Eveleth 6:30 p.m. Public Hearing Tr. (June 19, 2017) (eDocket No. 20177-134054-01); Duluth 2:00 p.m. Public Hearing Tr. (June 20, 2017) (eDocket No. 20177-134054-03); Duluth 6:30 p.m. Public Hearing Tr. (June 20, 2017) (eDocket No. 20177-134054-04); Grand Rapids Public Hearing Tr. (June 21, 2017) (eDocket No. 20177-134054-05); Little Falls Public Hearing Tr. (June 22, 2017) (eDocket No. 20177-134054-06).
[27] Ex. 87 at 21, MAP-S-2 (Podratz Surrebuttal).

17. A settlement conference was held, under Minn. Stat. § 216B.16, subd. 4 (2016), on July 25, 2017, with Administrative Law Judge Jeff Oxley. The parties were unable to resolve any of the disputed issues.

18. On August 2, 2017, a prehearing conference was held at the PUC's office in Saint Paul.

19. Prior to the evidentiary hearing, several parties filed motions in limine to exclude testimony. The Administrative Law Judge denied the motions.[28]

20. The evidentiary hearing was held from August 8 through 11, 2017, at the PUC's office in Saint Paul.[29]

21. On September 12, 2017, the parties filed initial briefs. Reply briefs were filed on September 28, 2017, and the record closed.

II. TEST YEAR REVENUE

A. Claimed Average Rate Base

22. In 2017, Applicant claims it had an average rate base of $2,092,387,441.[30]

23. The rate of return is 7.548 percent.[31]

24. Applicant claims its operating income is $129,090,471.[32]

25. The income deficiency claimed by Applicant is $28,842,933.[33]

26. The gross revenue conversion factor is 1.705611. This results in a gross revenue deficiency of $49,194,824 based on Applicant's claimed income deficiency.[34]

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[28] Order Denying LPI Motion in Limine to Exclude Testimony (Aug. 4, 2017) (eDocket No. 20178-134526-01); Order Denying ECC Motions in Limine to Exclude Testimony (Aug. 4, 2017) (eDocket No. 20178-134518-01); Order Denying Motions in Limine to Exclude Surrebuttal Testimony of Fleege (Aug. 7, 2017) (eDocket No. 20178-134557-01); Order Denying OAG Motion in Limine to Exclude Testimony (Aug. 7, 2017) (eDocket No. 20178-134547-01).

[29] Evidentiary Hearing Tr. Vol. 1 (eDocket No. 20178-134990-01); Evidentiary Hearing Tr. Vol. 2 (eDocket No. 20178-134990-03); Evidentiary Hearing Tr. Vol. 3 (eDocket No. 20178-134990-04); Evidentiary Hearing Tr. Vol. 4 (eDocket No. 20178-134990-05).

[30] Ex. 87, MAP-S-2 (Podratz Surrebuttal). All numbers are Minnesota Jurisdictional unless otherwise noted. However, due to the opacity of the record, the Administrative Law Judge may not have always recorded the correct number (total company or jurisdictional). Thus, it is recommended that the PUC require Applicant to clearly record the numbers it is relying on when submitting its final rate schedules and related documentation.

[31] Ex. 6, Sched. C-1 at 2 (Electric Cost of Service Study, Calendar 2017 General); Ex. 87, MAP-S-2 (Podratz Surrebuttal).

[32] Ex. 87, MAP-S-2 (Podratz Surrebuttal).

[33] *Id.*

[34] Ex. 87, MAP-S-2 (Podratz Surrebuttal). Many parties objected to this final revision.

B. Sub-Issues Related to Calculating Rate Base

i. Boswell Energy Center

27. Boswell Energy Center (BEC) is Applicant's largest thermal generation facility with four units (BEC1-BEC4) fueled by coal that have a combined total capacity of over 1000 MW.[35] The generator units were put into service in 1958, 1960, 1973, and 1980.[36] The four units and the common facilities share electrical, water, and heating infrastructure, ancillary services, and fuel handling.[37]

28. Applicant owns only 80 percent of BEC 4.[38]

29. BEC 1 and BEC 2 provide support to BEC 3 and BEC 4 during black-start procedures, on-going operations, and during critical system restoration activities.[39]

30. Since 2007, substantial investments have been made at BEC, including environmental retrofits of BEC3 and BEC4.[40]

31. BEC1 and BEC2 are currently treated as one unit for accounting and depreciation purposes. BEC3, BEC4, and the BEC common facilities are each treated as individual units for accounting and depreciation purposes.[41] The current remaining lives of the generator units for depreciation purposes are as follows: BEC1 and BEC2 until 2024, BEC3 until 2034, BEC4 until 2035, and the common facilities until 2030.[42]

32. In November 2015, Applicant petitioned the PUC for approval to consolidate the four BEC units and their common facilities into one unit for accounting purposes, and extend the singular unit's remaining useful life to 2050 for depreciation purposes.[43] In September 2016, Applicant withdrew the petition.[44]

33. In October 2016, Applicant announced that it will close down energy production from BEC1 and BEC2 at the end of 2018.[45]

34. As part of this rate case, Applicant has renewed its request to consolidate all components of BEC into one accounting unit and extend the remaining useful life to 2050 for depreciation purposes.[46] This proposal will save $22.7 million annually.[47]

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[35] Ex. 40 at 16 (Minke Direct).
[36] Ex. 44 at 4 (Skelton Direct).
[37] Ex. 46 at 16-17 (Skelton Rebuttal).
[38] Ex. 44 at 4 (Skelton Direct).
[39] Ex. 40 at 19 (Minke Direct).
[40] *Id.* at 16.
[41] Ex. 44 at 4 (Skelton Direct).
[42] Ex. 40 at 17 (Minke Direct).
[43] *Id.* at 14-15; *see also* MPUC Docket No. E015/M-15-988.
[44] Ex. 40 at 14-15 (Minke Direct).
[45] *Id.*
[46] *Id.* at 15.
[47] *Id.* at 20.

35. With appropriate maintenance and investments into replacements and upgrades BEC could be operated until 2050.[48] Applicant does not currently intend to operate BEC 3 beyond 2034 and BEC 4 beyond 2035.[49]

ii. Transmission Capital Projects

36. In order to ensure system reliability, Applicant invests in maintaining and upgrading its transmission system. There are two types of capital investments Applicant makes in its transmission system: large, multi-year capital projects, and smaller capital projects that are completed in a shorter period of time.[50]

37. Transmission projects are categorized into five groups, with some overlap. Transmission base is a category primarily for managing the health and performance of transmission assets.[51]

38. The main goal for transmission base projects is to ensure critical assets, including transmission lines, substations, and other related assets, meet reliability and capacity requirements, while minimizing life-cycle costs.[52]

39. Reliability projects are constructed to ensure the transmission system is compliant with all North American Electric Reliability Corporation (NERC) reliability standards.[53]

40. New business or customer need is a category of projects that must be constructed in order to meet the FERC Open Access Transmission Tariff (OATT) to accommodate the interconnection requests from generators, transmission lines, and new load.[54]

41. Regional expansion is a category that includes major high-voltage transmission line projects developed through the regional planning process.[55]

42. Finally, the "other" category includes transmission facilities that are primarily generator outlet lines and interconnection facilities.[56]

43. Applicant invests in two types of transmission capital projects: large multi-year projects and smaller projects completed in a shorter period of time.[57]

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[48] *Id.* at 18, HGM-10.
[49] *Id.* at 15; Ex. 42 at 8 (Minke Rebuttal).
[50] Ex. 49 at 13 (Fleege Direct).
[51] *Id.* at 12.
[52] *Id.*
[53] *Id.*
[54] *Id.*
[55] *Id.*
[56] *Id.* at 13.
[57] *Id.* at 10.

44. Applicant classifies capital projects according to the purpose that initiated development of the project, even if it serves multiple purposes.[58]

45. Initially Applicant proposed inclusion of 13 transmission capital investment projects for a total of $556.83 million, total company.[59] The project names and claimed costs (in millions) are:

NERC Projects	$68.63[60]
North Shore Loop	$20.08[61]
Badoura 115kV Transmission Project	$2.03[62]
Savanna 115 kV Transmission Project	$5.01[63]
Deer River 115 kV Transmission Project	$16.65[64]
Straight River 115 kV Transmission Project	$2.51[65]
Dog Lake	$4.13[66]
Nashwauk 230 kV/115 kV Transmission Facility Projects	$31.14[67]
39 Line 115 kV Transmission Facility Project	$5.77[68]
Canisteo 115 kV Transmission Facility Project	$13.12[69]

58 *Id.* at 13.
59 *Id.*, CEF-1.
60 *Id.* at 33, CEF-1.
61 *Id.* at 39, CEF-1.
62 *Id.* at 17, CEF-1.
63 *Id.* at 21, CEF-1.
64 *Id.* at 24, CEF-1.
65 *Id.* at 27, CEF-1.
66 *Id.,* CEF-1.
67 *Id.* at 42, CEF-1.
68 *Id.* at 48, CEF-1.
69 *Id.* at 52, CEF-1.

Bemidji Grand Rapids 230 kV Transmission Project	$10.11[70]
Monticello Fargo 345 kV Transmission Facility Project	$89.38[71]
Great Northern Transmission	$248.28[72]

46. Applicant removed two projects worth $4.3 million: 5 Line Re-conductor and Hoyt Lakes Ring Bus Reconfiguration.[73] In place of the two projects, Applicant added five other projects that need to be completed in 2017 worth $4.6 million: No. 109078 North Shore 115 kV Switch Station; No. 109253 ETCO Capacitor Bank; No. 109039 Forbes 3T Breaker & 3TR Panel; No. 109047 Boswell 95 Line Upgrade and No. 109052 Blackberry 95 Line Upgrade (treated as one project); and No. 109176 Minntac 50L and No. 109177 Minntac 54L (treated as one project).[74]

47. Applicant supplied substantial and credible evidence to support its claims for transmission capital projects, demonstrating they are all reasonable and necessary.[75]

iii. Generation Capital Projects

48. Applicant's electricity generation comes primarily from coal-fired units, supplemented by wind and hydroelectric power.[76] In 2015, at least 25 percent of Applicant's electricity came from renewable sources.[77]

49. Generation capital investments fall into three categories: (1) base capital investments, (2) environmental improvement projects, and (3) renewable resource additions and refurbishments.[78]

50. Initially, Applicant planned 68 generation capital additions totaling $27,722,352.56.[79] Applicant provided detailed explanations for key projects from this list.[80]

51. Seven of the original list of generation capital projects, totaling $1,942,887, were postponed during the course of this proceeding, but the cost of the projects was not

[70] *Id.* at 54, 55, CEF-1.
[71] *Id.* at 58, CEF-1.
[72] *Id.,* CEF-1.
[73] Ex. 629, NAC-11 (Campbell Direct).
[74] *Id.*
[75] Ex. 49 (Fleege Direct); Ex. 50 (Fleege Rebuttal); Ex. 629, NAC-11 (Campbell Direct).
[76] Ex. 44 at 5 (Skelton Direct).
[77] *Id.* at 6.
[78] *Id.* at 9-10.
[79] Ex. 44 at 11, JJS-1 (Skelton Direct).
[80] *Id.* at 17-20, 26-28, 38.

removed from the calculations for the test year.[81] Applicant replaced six of these projects with higher priority projects totaling $1,209,791.[82]

52. Applicant provided detailed information about the postponed and replacement projects and the costs, but did not adjust the figures.[83]

iv. Storm Damage Amortization Expense

53. On August 1, 2016, Applicant petitioned the PUC for approval of deferred accounting treatment of costs related to its 2016 storm response and recovery.[84] Applicant incurred $2.9 million in storm cleanup costs.[85]

54. On January 10, 2017, the PUC denied the request because Applicant did not demonstrate that its non-fuel operating and maintenance expenses were unusual and unforeseen.[86] The PUC also determined that Applicant failed to show that the storm expenses would have a significant impact on its overall financial condition.[87]

55. In this rate case, Applicant initially sought to amortize $2,929,088 of incremental O&M expenses for 2016 storm repairs over four years starting in 2017.[88] The annual amortization expense adjustment is $732,272.[89]

56. Applicant has since removed the $732,272 annual amortization expense for the 2016 storm damage from the test year rate base.

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[81] Ex. 507, SL-R-1 at 5 (Lee Rebuttal).
[82] Ex. 46, JJS-R-1 at 5 (Skelton Rebuttal).
[83] Ex. 47 at 3-6, JJS-R-2 (Skelton Rebuttal – Trade Secret).
[84] *In re Pet. for Approval of Deferred Accounting Treatment of Costs Related to the 2016 Storm Response and Recovery*, MPUC Docket No. E-015/M-16-648, Petition for Approval (Aug. 1, 2016).
[85] *Id.*
[86] *In re Pet. for Approval of Deferred Accounting Treatment of Costs Related to the 2016 Storm Response and Recovery*, MPUC Docket No. E-015/M-16-648, Order Denying Petition for Deferred Accounting Treatment at 2, 4, 5 (Jan. 10, 2017).
[87] *Id.*
[88] Ex. 83 at 31 (Podratz Direct).
[89] *Id.*

v. Storm Restoration Budget

57. Historically, Applicant has not budgeted for storm response costs.[90] Such costs have been charged to the distribution function responsibility cost center (RC 190).[91]

58. For the 2017 test year, Applicant initially incorporated $5.7 million into combined company capital and associated operations and management (O&M).[92] This amount was based on a three-year average of expenses above the already-budgeted overtime amounts for 2014, 2015, and 2016.[93] The incremental O&M component is estimated at $2.929 million.[94] This amount was not included in the 2016 forecast, or the 2017 test year budget due to the timing of when this issue arose in 2016.[95]

59. Applicant updated its incremental O&M request to $1,680,267 (total company) for the test year based on actual 2016 costs.[96]

vi. Sappi/Cloquet Generator Amortization Expense

60. Applicant requested $275,745 in the test year as a deferred amortization expense for the Sappi/Cloquet Turbine TG5 generator.[97] This amount was later reduced to $232,618 using the 84.36 percent allocator.[98]

61. Applicant has removed the $232,618 deferred amortization expense from the test year rate base.[99]

vii. Credit Card Processing Fees

62. Applicant uses a third-party vendor for processing debit and credit card payments.[100]

63. When a customer uses a credit or debit card to pay a bill the customer is charged a transaction fee of $2.95 for each payment. This fee is paid to the third-party vendor.[101]

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[90] Ex. 49 at 74 (Fleege Direct).
[91] *Id.* at 73.
[92] *Id.*
[93] Ex. 50 at 15, CEF-R-5 (Fleege Rebuttal).
[94] Ex. 49 at 73 (Fleege Direct).
[95] *Id.* at 74.
[96] Ex. 50 at 13 (Fleege Rebuttal); Evidentiary Hearing Tr. Vol. 4 at 125 (Campbell).
[97] Ex. 629 at 10 (Campbell Direct).
[98] *Id.*
[99] Ex. 86 at 7-8 (Podratz Rebuttal).
[100] Ex. 76 at 28 (Koecher Direct).
[101] *Id.*

64. Applicant has proposed to eliminate the individual per transaction fee for customers. Instead, Applicant would incur the fee as part of the company's overall O&M expense, similar to how it pays the costs for other business transactions.[102]

65. Applicant assumes that with the elimination of the fee for customers, the use of debt and credit cards for payment will rise from five percent to 15 percent.[103]

66. For the 2017 test year, Applicant estimates the cost for processing debit and credit card payments through its vendor will be $350,000.[104]

viii. Charitable Contributions and Administrative Costs of Minnesota Power Foundation

67. The Minnesota Power Foundation is an organization that distributes funds to charities in Applicant's name.[105] Each year the organization distributes nearly $1 million in grants, scholarships, and sponsorship to support charitable groups in education, community enrichment, arts and culture, and health and human services.[106]

68. Applicant seeks $394,280 in the test year rate base for charitable contributions, an amount based on an average of 50 percent of the annual qualified charitable contributions for the three years 2013 through 2015.[107]

69. An average of 50 percent of the annual qualified contributions for 2014, 2015, and 2016 is approximately $359,250.[108]

70. Applicant also seeks $114,597 for the administration of its charitable Foundation, which enables Applicant to distribute the charitable funds.[109]

71. In 2015, Applicant made 241 charitable contributions to nearly that many different organizations within its service territory.[110] These contributions strengthen communities and enhance the quality of life for people served by Applicant.[111]

ix. Travel, Entertainment, and Related Employee Expenses

a. Membership Dues

[102] *Id.* at 29.
[103] *Id.* at 32.
[104] *Id.* at 31.
[105] Ex. 626 at 2 (La Plante Direct).
[106] *Id.*
[107] Ex. 17, Sched. A-6 at 1 (Supplemental Direct Filing Vol. 2); Ex. 83 at 23 (Podratz Direct).
[108] Ex. 505 at 46 (Lee Direct).
[109] Ex. 626 at 3, LL-1 (La Plante Direct).
[110] Ex. 6, Sched. G-2 (Initial Filing Vol. 4).
[111] Ex. 33 at 25-26 (McMillan Rebuttal); Ex. 626 at 5 (La Plante Direct).

72. Applicant pays dues for corporate memberships, individual memberships, and regional memberships to a variety of entities.[112]

73. Initially Applicant requested $789,962 in the 2017 test year for total organizational dues.[113]

74. The requested amount was decreased by $17,514 due to the lobbying activities of some of the organizations.[114] The resulting total was $772,448.

75. The work of three of the organizations Applicant is seeking recovery of dues for – Edison Electric Institute, National Hydropower Association, and Western Coal Traffic League – is reasonable, appropriate, and provides indirect benefit to Applicant's customers.[115] The allowable cost of membership in these organizations is $417,946.[116]

b. Employee Gifts

76. Applicant provides employee recognition gifts, bonuses, and awards.[117]

77. Applicant's policy in the Employee's Handbook refers to employee recognition gifts that are "appropriate and reasonable for the work performed and meaningful to the employee."[118] "Employee recognition, gifts, and bonuses include High Performance Awards, Extraordinary Compensation, Spot / Project Bonuses, Gift Cards, Non-Monetary Gifts and Safety Awards, Special Time Off with Pay, Recognition Meals and Events, and other employee recognition."[119]

78. Retirement and service awards are administered by ALLETE's human resources department.[120] "Service and retirement are determined according to set procedures and policies of Human Resources based on length of service and are, therefore, considered non-discretionary."[121] The record lacks detail about these procedures and policies.[122]

79. Applicant seeks to recover $23,007 (total company) for safety, length of service, and retirement awards in the test year.[123] These gifts support the provision of safe utility service at reasonable cost by supporting employee retention.[124]

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[112] Ex. 6, Sched. G-3 (Initial Filing Vol. 4).
[113] Ex. 6, Sched. G-3 (Initial Filing Vol. 4); Ex. 55 at 19 (Morris Rebuttal).
[114] Ex. 6, Sched. G-3 (Initial Filing Vol. 4); Ex. 55 at 19 (Morris Rebuttal).
[115] Ex. 55 at 15-17, SWM-R-3, SWM-R-4 (Morris Rebuttal).
[116] *Id.*, SWM-R-5.
[117] Ex. 53, SWM-9 at 14-17 (Morris Direct).
[118] *Id.* at 14.
[119] *Id.* at 14-15.
[120] *Id.* at 17.
[121] Ex. 505, SL-19 at 2-3 (Lee Direct).
[122] *See, e.g.,* Ex. 53, SWM-11 (Morris Direct); Ex. 55 at 20-21 (Morris Rebuttal); Ex. 56 at 3, NRJ-3, NRJ-4 (Johnson Direct); Ex. 58 at 37 (Johnson Rebuttal).
[123] Ex. 55 at 20, SWM-R-11 (Morris Rebuttal).
[124] Ex. 6, Sched. I (Initial Filing Vol. 4).

80. Applicant withdrew its request for employee gifts for exceptional performance, which totaled $79,500 (total company).[125]

c. Remaining Expenses

81. Applicant's budget process is a "bottom up process" undertaken by each Responsibility Center at the company.[126] For employee expenses, each Responsibility Center projects the amount of employee expenses it expects, and the amounts are aggregated into an overall employee expense budget.[127]

82. The initial total aggregated was $6,373,590 (total company).[128] Applicant then analyzed 2015 employee expense data to identify expenses to exclude from the test year budget.[129] Excluded expenses included employee recognition expenses (except for safety achievement recognition), foreign travel (except when related to utility operations), lobbying, and 50 percent of investor relations.[130] The total reduction was $1,620,291, which resulted in a new total aggregate of $4,753,299, which Applicant seeks to recover in this matter.[131]

83. Employee expenses claimed which did not include a vendor name total $27,520 (total company).[132] Many of these itemizations did not include a business purpose.[133]

x. Prepaid Pension Asset

84. Most years, Applicant makes contributions to its pension plan to ensure adequate funding to cover future benefit obligations to employees.[134] When Applicant contributes more to the pension plan than it has expensed, the result is a prepaid pension asset.[135]

85. Currently, Applicant is recovering through rates an amount of pension expense based on a five-year average that was calculated in its 2009 rate case.[136]

86. In this rate case, Applicant seeks recovery of $27,816,947 for its prepaid pension asset.[137]

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[125] Ex. 55 at 20 (Morris Rebuttal).
[126] *Id.* at 2.
[127] *Id.*
[128] *Id.* at 3.
[129] *Id.*
[130] *Id.*
[131] *Id.*
[132] Ex. 505, SL-23 at 54-66 (Lee Direct).
[133] *Id.*; *see also* Ex. 55 at 8-11 (Morris Rebuttal).
[134] Ex. 37 at 61 (Cutshall Direct).
[135] *Id.*
[136] *Id.* at 63.
[137] *Id.* at 71.

xi. High-level Employee Related Expenses

87. Applicant seeks to recover expenses for certain high-level employee compensation, including two non-qualified deferred compensation (NQDC) plans: Executive Deferral Account (EDA) and Executive Investment Plan (EIP); and its Annual Incentive Program (AIP).[138]

88. The NQDC plans provide management-level employees the opportunity to save for retirement through a salary or bonus deferral which are above IRS limitations on contributions to qualified deferred compensation plans.[139]

89. EDA is for current management-level employees, and EIP is for retired management-level employees.[140]

90. AIP is an incentive plan offered to 190 supervisory or other key employees to supplement their base pay. It is intended to bring compensation more in-line with market pay and obtain higher performance from the benefitting employees.[141]

91. These compensation plans are important benefits to obtain and retain qualified management-level employees in the current labor market. In this way, they help to provide safe and reliable electric service at a reasonable cost.[142]

92. Applicant will limit the level of incentive compensation to no more than 20 percent of individual base salaries.[143]

93. Applicant seeks $1,160,890 for EDA expenses, $150,097 for EIP expenses, and $2,722,990 for AIP.[144]

xii. Unfilled Positions

94. Applicant initially sought recovery of $82,621,828 (total company) for employee compensation during the 2017 test year.[145]

95. However, during the first quarter of 2017, some of the full-time employee positions were unfilled. Specifically, 46 positions during January 2017, 51 positions during February, and 45 positions during both March and April 2017 were unfilled.[146]

96. Applicant agreed to reduce its employee compensation cost by $2,662,793 to account for unfilled positions. It calculated these amounts by using the actual

[138] Ex. 56, NRJ-3 (Johnson Direct); Ex. 58 at 23-24 (Johnson Rebuttal).
[139] Ex. 56 at 50-51 (Johnson Direct); Ex. 58 at 23-24 (Johnson Rebuttal).
[140] Ex. 58 at 24 (Johnson Rebuttal).
[141] Ex. 56 at 13, 17 (Johnson Direct).
[142] *Id.* at 18, 21; Ex. 58 at 14, 17, 24-25 (Johnson Rebuttal).
[143] Ex. 56 at 20 (Johnson Direct).
[144] *Id.*; Ex. 58, NRJ-R-4 (Johnson Rebuttal).
[145] Ex. 631 at 24 (Lusti Direct).
[146] *Id.* at 23, DVL-17.

headcount differences for the first five months of 2017, and the May 2017 headcount for the remaining seven months of 2017, which yielded a reduction to the test-year head count of 3.46 percent.[147]

97. Applicant calculated a related adjustment reducing the associated employment benefits by $306,828.[148]

98. The total adjustment is $2,969,621.[149]

xiii. Test Year Cash Working Capital (CWC)

99. CWC represents the amount of money needed to meet current operating expenses incurred prior to collecting revenues for the service provided.[150]

100. CWC is adjusted to reflect the impact of various O&M expense adjustments to the test year budget, including advertising expense, economic development, charitable contributions, and organizational dues.[151] In addition, the state and federal income taxes included in CWC reflect interest synchronization and the tax impact of the revenue deficiency.[152]

101. The most precise method of determining CWC is to perform a lead/lag study.[153] A lead/lag study measures the difference between the period of time the utility has to pay for the expenses to provide service to customers (expense lead) and the period of time it takes the utility to collect revenues from its customers (revenue lag).[154]

102. Applicant prepared a lead/lag study in 2012, and the resulting CWC calculation was consistent with the approach and methodology used by the company and approved by the Commission in Docket No. E015/GR-09-1151 in a 2006 lead/lag study.[155]

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[147] Ex. 58 at 6 (Johnson Rebuttal).
[148] *Id.*
[149] *Id.*; Ex. 632 at 19 (Lusti Surrebuttal).
[150] Ex. 82 at 11 (Podratz Direct); Ex. 102 at 3 (Rackers Direct).
[151] Ex. 82 at 16 (Podratz Direct).
[152] *Id.*
[153] Ex. 102 at 3 (Rackers Direct); *see also* Ex. 82 at 11 (Podratz Direct).
[154] Ex. 102 at 3 (Rackers Direct).
[155] Ex. 82 at 11 (Podratz Direct).

xiv. Production Tax Credits and Prorated Accumulated Deferred Income Taxes

103. Production tax credits (PTCs) result from the generation of electricity using renewable resources and are intended to act as a financial incentive to support the development of renewable energy facilities.[156]

104. Applicant first began generating PTCs with its construction of the Taconite Ridge Wind Energy Center in 2008.[157]

105. Bonus depreciation operates as an accelerated tax deduction, and its utilization increases the amount of accumulated deferred income taxes (ADIT).[158] The cash benefit of depreciation is recorded as an Accumulated Deferred Income Tax Asset (ADITA).[159]

106. In this rate case, Applicant incorporated existing PTC deferred tax assets from its wind generation projects into the ADIT, beginning with interim rates.[160] For the Bison wind projects, the inclusion of the PTCs and the ADITA for PTCs will be neutral to overall rates.[161] For the Taconite Ridge wind project, the inclusion of the ADITA for PTCs will result in an increase in rate base.[162]

107. Initially, Applicant requested inclusion of $131,032,771 of PTCs in the rate base.[163]

108. Applicant subsequently agreed with the Department to lower the deferred tax expense by $1,462,487 with a corresponding adjustment to the ADITA, which would increase the rate base by $731,243.[164]

xv. Fuel Clause Adjustments

a. Fuel Clause Adjustment Methodology

109. The fuel clause is the mechanism through which Applicant is able to account for any over- or under-recovery associated with providing energy to its customers.[165] Key costs in the fuel clause adjustment include fuel and its related transportation costs, energy

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156 Ex. 74 at 13 (Jago Direct).
157 *Id.*
158 *Id.* at 3.
159 *Id.* at 4.
160 *Id.* at 14.
161 *Id.*
162 *Id.*
163 *Id.* at 15.
164 Ex. 75 at 5 (Jago Rebuttal).
165 Ex. 72 at 2 (Oehlerking-Boes Direct).

costs of bilateral purchases made to cover firm load, Day Ahead and Real Time MISO[166] market purchases, and associated MISO market costs.[167]

110. Applicant currently administers its fuel clause adjustment under the FPE Rider approved by the PUC in Docket E015/GR-09-1151.[168]

111. In its 2008 rate case, Applicant proposed a change to its fuel clause adjustment methodology, but subsequently withdrew the request as part of a voluntary settlement.[169]

112. In this rate case, Applicant is proposing to change its fuel clause adjustment methodology to use forecasts with a periodic true-up.[170]

113. Applicant subsequently withdrew its fuel clause adjustment methodology proposal and requests that a decision on fuel clause adjustment be delayed until the PUC resolves *In re an Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments*, MPUC Docket No. E999/CI-03-803.[171]

b. Fuel Clause Transition Cost Recovery

114. Applicant seeks to recover the cost of transitioning from use of the current fuel clause adjustment methodology to use of a new fuel clause adjustment methodology.[172]

115. Initially Applicant sought to amortize $18.5 million worth of uncollected fuel expense over 36 months.[173] Applicant refers to this expense as the fuel cost recovery delay amount.[174]

116. Applicant subsequently requested to delay calculation and recovery until the PUC determines a new methodology for calculating fuel clause adjustments in Docket No. E999/CI-03-803.[175]

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[166] MISO is Midcontinent Independent System Operators, an independently operated regional energy transmission system.
[167] Ex. 72 at 2 (Oehlerking-Boes Direct).
[168] *Id.* at 4.
[169] *Id.* at 11.
[170] *Id.* at 6-10.
[171] Applicant Initial Brief (Br.) at 89-93 (Sept. 12, 2017) (eDocket No. 20179-135459-02).
[172] Ex. 72 at 18 (Oehlerking-Boes Direct).
[173] *Id.*; Ex. 73 at 4-5 (Oehlerking-Boes Rebuttal); Ex. 101 at 9 (Gorman Direct).
[174] Ex. 72 at 18-19 (Oehlerking-Boes Direct).
[175] Applicant Initial Br. at 90-92 (Sept. 12, 2017) (eDocket No. 20179-135459-02).

c. Base Cost of Fuel

117. Applicant's current base cost of fuel is 1.018 cents per kilowatt hour (kWh), which was approved in Applicant's 1994 rate case and affirmed in its 2008 and 2009 rate cases.[176]

118. At the time of filing, Applicant's calculation for the base cost of fuel for the 2017 test year was 2.103 cents per kWh.[177]

119. The calculation increased to 2.121 cents per kWh during this proceeding.[178]

120. Initially Applicant proposed to include the new base cost of fuel in the fuel clause adjustment line item on customer bills and remove it from base rates.[179]

121. Applicant subsequently requested that the base cost of fuel issue be deferred to Docket No. E999/CI-03-802.[180]

d. Chemical and Reagent Costs

122. Applicant utilizes reagents and chemicals to reduce emissions at its generation plants.[181] Typically the reagents and chemicals are introduced during combustion and use kinetics to drive pollutants into forms that can be scrubbed or removed from the flue gas streams.[182] The reagents and chemicals can also be used to avoid the formation of certain pollutants.[183]

123. Applicant's use of reagents and chemicals at a particular generation plant is directly correlated to the plant's number of operational hours, generation levels (load), and fuel blend.[184]

124. In this rate case, Applicant seeks recovery of the cost of generation facility chemicals and reagents.[185] The 2017 test year budget for reagents and chemicals is $4,000,954.[186]

125. Applicant has not previously asked to recover the costs of reagents and chemicals in a rate case because the costs have been consistent and have not previously accounted for a large portion of O&M expenses.[187]

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[176] Ex. 72 at 3 (Oehlerking-Boes Direct).
[177] *Id.*
[178] Ex. 84 at 12 (Podratz Supplemental Direct).
[179] *Id.*
[180] Evidentiary Hearing Tr. Vol. 1 at 193 (Oehlerking-Boes).
[181] Ex. 44 at 54 (Skelton Direct).
[182] *Id.*
[183] *Id.*
[184] *Id.* at 55.
[185] Ex. 72 at 24 (Oehlerking-Boes Direct).
[186] *Id.*
[187] *Id.* at 25.

e. Business Interruption Insurance

126. Since 2013, Applicant has maintained business interruption insurance coverage on its DC line from the Bison wind farm in North Dakota.[188]

127. Business interruption insurance is intended to shield customers from the added costs of spot market pricing for replacement power and lost PTCs in the event the Bison wind farm or the DC Line are offline.[189]

128. Applicant seeks to recover business interruption insurance premiums through the fuel clause.[190] The 2017 test year premiums are $299,875.[191]

f. Nitrous Oxide (NO_x) Allowances

129. Emissions from generation plants are regulated by the United States Environmental Protection Agency (EPA) through allowance requirements.[192] Allowances play an important role in a utility's environmental compliance planning because the utility must ensure sufficient allowances exist to cover its own compliance, and must correctly surrender, balance, and allocate allowances monitored by the EPA.[193]

130. Allowances that are not used by a utility can be saved or sold within certain restrictions.[194]

131. Applicant's allowance needs are dependent on the amount of fuel burned at its generation facilities from year to year.[195]

132. In 2008, the PUC gave Applicant the ability to debit and credit the purchase and sale of sulfur dioxide (SO_2) allowances through the fuel clause adjustment (FCA) rider.[196]

133. In this rate case, Applicant requests the ability to debit and credit the purchase and sale of NO_x allowances through the FCA rider.[197]

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[188] *Id.* at 26.
[189] *Id.*
[190] *Id.* at 27.
[191] *Id.*
[192] Ex. 44 at 61 (Skelton Direct).
[193] *Id.*
[194] *Id.*
[195] *Id.* at 62.
[196] *In re App. of Minn. Power for Auth. to Increase Elec. Serv. Rates in Minn.* MPUC Docket No. E-015/GR-08-415, Order After Reconsideration at 3 (Aug. 10, 2009).
[197] Ex. 72 at 29 (Oehlerking-Boes Direct).

g. Generation O&M: Supervision and Engineering Expenses and Meter Reading Expenses

134. The generation O&M budget is based on expenses incurred while operating and maintaining the assets in a utility's generation portfolio.[198] The majority of a generation O&M budget consists of internal and contractor labor required to operate generation facilities on a day-to-day basis as well as necessary maintenance and repairs.[199]

135. Applicant's budgeting for generation O&M expenses changed from the 2012-16 period to the 2017 test year.[200] Cost controls, changes to generating units resulting in significant salary, wage, and benefit differences, and refocusing efforts from capital projects to O&M all contributed to the budgeting changes.[201]

136. The 2017 test year budget is based on input from all 80 of Applicant's departments or responsibility centers, each of which has expertise in its specific area.[202] Each generation plant is a responsibility center.[203]

137. In this rate case, Applicant's budgets for the 2017 test year generation O&M include $1,138,982 for meter reading expenses and $21,404,691 for generation supervision and engineering expenses.[204]

xvi. Sales Forecasts – Keetac

138. U.S. Steel is the largest integrated steel producer in the U.S. and has two mining operations in northern Minnesota: Minntac and Keetac.[205] Applicant provides electric service to both facilities.[206]

139. Due to low demand, U.S. Steel idled Keetac in April 2015.[207]

140. In December 2016, U.S. Steel announced plans to restart Keetac in 2017.[208]

141. Applicant updated its sales forecast for the 2017 test year because of the restart of Keetac. The revised forecast is based on nine months of electricity sales to U.S. Steel for the Keetac in 2017.[209] The revised forecast assumes a 4.5 million ton increase

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[198] Ex. 44 at 45 (Skelton Direct).
[199] *Id.*
[200] Ex. 46 at 9, 12-15 (Skelton Rebuttal).
[201] *Id.* at 12; Ex. 58 at 4 (Johnson Rebuttal).
[202] Ex. 53 at 2-4 (Morris Direct).
[203] *Id.*
[204] Ex. 624 at 30 (Ouanes Direct).
[205] Ex. 61 at 18 (Perala Direct).
[206] *Id.*
[207] *Id.*
[208] Ex. 64 at 3 (Perala Second Supp. Direct).
[209] *Id.*

in taconite production, or 37 million tons total for the six mines served by Applicant.[210] The total capacity of the six mines is 41 million tons annually.[211] Thus, Applicant's sales forecast has been updated to reflect electric sales for 90 percent utilization of the capacity of the six mines.[212]

142. The mining industry is highly volatile, and from 2006 through 2016, the total production of taconite from Applicant's customers ranged from a low of 41 percent utilization in 2009, to highs of 95 percent utilization in 2006, 2008, 2011, 2012, and 2014.[213] The ten year average from 2006 through 2016 is 84 percent utilization.[214]

xvii. Taconite Harbor Re-Start/Re-Idle

143. Coal-fired units 1 and 2 of Taconite Harbor Energy Center (THEC) will be retired by the end of 2020.[215]

144. In 2016, the PUC approved Applicant's plan to idle the two units.[216] However, periodic restarting of the units is necessary to demonstrate air emissions compliance and MISO market accreditation.[217] The units will need to be restarted at least twice between 2017 and 2020.[218]

145. The units may also need to be restarted to provide power in the MISO capacity auction each year between 2017 and 2020.[219]

146. The cost of each restart and return to idle sequence is estimated at $1.25 million.[220]

147. Applicant is planning to restart the units at least once per year between 2017 and 2020.[221]

xviii. Solar Energy Standard (SES) Capacity Benefits

148. The Camp Ripley Solar Project is a 10 MW solar facility constructed at Camp Ripley, a Minnesota Army National Guard base near Little Falls, Minnesota.[222]

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[210] *Id.* at 5.
[211] *Id.*
[212] *Id.*
[213] Ex. 65 at 7 (Perala Rebuttal).
[214] *Id.*
[215] Ex. 44 at 20-22 (Skelton Direct).
[216] *Id.* at 20; *In re Minn. Power's 2016-2030 Integrated Res. Plan*, MPUC Docket No. E015/RP-15-690, Order Approving Resource Plan with Modifications at 5 (July 18, 2016).
[217] Ex. 44 at 20-22 (Skelton Direct).
[218] *Id.*
[219] Ex. 48 at 3 (Skelton Surrebuttal); *In re Minn. Power's 2016-2030 Integrated Res. Plan*, MPUC Docket No. E015/RP-15-690, Order Approving Resource Plan with Modifications at 5 (July 18, 2016).
[220] Ex. 44 at 22 (Skelton Direct).
[221] Ex. 48 at 4 (Skelton Surrebuttal).
[222] *In re Pet. of Minn. Power for Approval of Investments and Expenditures in the Camp Ripley Solar Project for Recovery Through Minn. Power's Renewable Res. Rider Under Minn. Stat. 216B.1645 and Related*

149. As part of this rate case, the PUC directed Applicant to develop and provide a methodology for allocating Camp Ripley's solar capacity benefits between SES exempt customers and solar paying customers.[223]

150. Applicant proposes to calculate the value of solar capacity based on the clearing price for capacity in MISO's annual Planning Resource Auction in Local Resource Zone 1.[224]

151. Applicant proposes to base the MW value used to calculate the solar capacity on the MISO Zonal Resource Credits (ZRC) assigned to Camp Ripley or future SES solar projects through the MISO Resource Adequacy Program.[225]

152. Applicant proposes that each month the total SES capacity value be based on the solar ZRCs multiplied by the most recent clearing price from the MISO Planning Resource Auction for capacity in Local Resource Zone 1.[226]

III. PROPOSED CAPITAL STRUCTURE AND RETURN ON EQUITY

153. Capital structure relates to a company's financial risk, which is the risk that a company may not have adequate cash flows to meet its financial obligations.[227]

154. As an operating division of ALLETE, Applicant has a capital structure derived from ALLETE's consolidated capital structure, which includes common equity and debt that finances all of ALLETE's business activities, including subsidiary operations.[228]

155. Applicant's capital structure used for ratemaking purposes is calculated by starting with ALLETE's capital structure and extracting the debt of ALLETE's subsidiaries and ALLETE's equity and debt investments in the subsidiaries.[229]

156. The cost of equity is the return that investors require to make an equity investment in a company.[230] Return on equity (ROE) measures a company's profitability by revealing how much profit a company generates with the money provided by investors, divided by equity.[231]

Tariff Modifications, MPUC Docket No. E015/M-15-773, Order Limiting Cost Recovery, Approving Fuel and Purchased Energy Adjustment Rider Revisions, and Approving Proposed Solar Energy Adjustment Rider (Dec. 12, 2016).

[223] *In re Pet. of Minn. Power for Approval of Investments and Expenditures in the Camp Ripley Solar Project for Recovery Through Minn. Power's Renewable Res. Rider Under Minn. Stat. 216B.1645 and Related Tariff Modifications*, MPUC Docket No. E015/M-15-773, Order Limiting Cost Recovery, Approving Fuel and Purchased Energy Adjustment Rider Revisions, and Approving Proposed Solar Energy Adjustment Rider (Dec. 12, 2016).

[224] Ex. 67 at 42 (Pierce Direct).

[225] *Id.*

[226] *Id.* at 42-43.

[227] Ex. 34 at 50 (Hevert Direct).

[228] Ex. 27 at 5 (Cutshall Direct).

[229] *Id.*

[230] Ex. 34 at 10-11 (Hevert Direct).

[231] *Id.*

157. In Applicant's last rate case, in 2010, the equity ratio was set at 54.29 percent.[232]

158. The current average cost of long-term debt for Applicant is 4.517 percent.[233]

159. In order to determine a reasonable cost of equity for the Applicant, the cost of common equity must be inferred from market data for companies that present similar investment risks.[234]

160. Initially Applicant proposed a capital structure of 53.81 percent common equity and 46.19 percent long term debt with a 10.25 percent ROE.[235] During this proceeding, Applicant revised its proposed ROE from 10.25 percent to 10.15 percent with a range of 9.75 percent to 10.25 percent.[236] Applicant's proposed cost of capital summary and rate of return look like:

Average for 13 Months Ending December 31, 2017

	Amount	**% of Total**	**Component Cost**	**Weighted Cost**
Long-Term Debt	$1,228,550	46.189%	4.517%	2.086%
Common Equity	$1,431,272	53.811%	10.15%	5.462%
Total Capitalization	$2,659,822	100.00%		7.548%

161. Applicant's proposal is based on use of the following analytical models: the Constant Growth Discounted Cash Flow (DCF) model, the Two-Growth DCF model, the Capital Asset Pricing Model (CAPM), and the Bond Yield Plus Risk Premium (BYPRP) model.[237]

162. Using the models, Applicant focused on five factors to arrive at its proposed capital structure and return on equity: relative risk, return on equity, common equity ratio, nature and cost of debt, and impact to credit metrics of alternative outcomes.[238] This method added a highly subjective element to the analysis because it requires the evaluator to consider the results of each model and then use these factors to craft a result that is not directly based on a calculation.[239]

163. Because Applicant issues no equity, a proxy group was necessary to run the analytical models.[240] Applicant's proxy group consisted of the following companies:

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[232] *In re Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E-015/GR-09-1151, Findings of Fact, Conclusion and Recommendation at 28 (Aug. 17, 2010).
[233] Ex. 601 at 42 (Amit Direct).
[234] *In re Application of Minn. Energy Resources Corp. for Auth. to Increase Rates for Natural Gas Serv. in Minn.*, MPUC Docket No. G-011/GR-15-736, Findings of Fact, Conclusions, and Order at 19 (Oct. 31, 2016).
[235] Ex. 27 at 2 (Cutshall Direct).
[236] Ex. 35 at 3 (Hevert Rebuttal).
[237] Ex. 34 at 4, 24-36 (Hevert Direct). The DCF models are variants of one model.
[238] *Id.* at 4.
[239] *Id.* at 19-20; Ex. 601 at 59 (Amit Direct).
[240] *Id.* at 15.

Alliant Energy, Black Hills, El Paso Electric, OGE Energy, Otter Tail, Pinnacle West Capital, PNM Resources, Portland General Electric, and SCANA.[241]

164. Excluded from the proxy group using the following screen were:

- Companies that do not consistently pay quarterly cash dividends;
- Companies that were not covered by at least two utility industry equity analysts;
- Companies that do not have investment grade senior unsecured credit ratings, or investment grade corporate issuer credit ratings from Standard & Poor's (S&P);
- Companies that were not vertically-integrated, *i.e.* utilities that do not own and operate regulated generation, transmission and distribution assets;
- Companies whose regulated operating income over the three most recently reported fiscal years comprised less than 60 percent of the respective totals for that company;
- Companies whose regulated electric operating income over the three most recently reported fiscal years 1 represented less than 60 percent of total regulated operating income;
- Companies with a market capitalization greater than $10 billion, or "large cap" companies;
- Companies that are currently known to be party to a merger or other significant transaction; and
- Companies with mean DCF results of less than 8 percent.[242]

165. An appropriate proxy group for running the model is:

- ALLETE Inc.
- Alliant Energy Corp.
- Ameren Corp.
- American Electrical Power Co.
- Avista Corp.
- DTE Energy Co.
- Edison International
- El Paso Electrical Co.
- IDACORP Inc.
- Northwestern Corp.
- PG&E Corp.
- Pinnacle West Capital Corp.
- PNM Resources Inc.
- Portland General Electric Co.
- SCANA Corp.

[241] Ex. 35 at 7 (Hevert Rebuttal).
[242] Ex. 34 at 16-17 (Hevert Direct).

- WEC Energy Group Inc.
- Xcel Energy Inc.[243]

166. Applicant relied on 30, 90, and 180 day stock prices in running the DCF models.[244]

167. The ROE must be set based on current market conditions to reflect the current cost of capital and attract investors. The ROE should not be based on historical data.[245]

168. Under current market conditions, an appropriate low-end cutoff screen is seven percent.[246]

169. When a low-end screen is used, a high-end screen should also be used to ensure there are not inappropriately skewed results.[247]

170. The risk premium differential between an eight percent ROE and the yield on 20-year treasury bonds is only 5.46 percent.[248]

171. The Two-Growth DCF model accounts for outlier companies because it reflects all of their current market data.[249]

172. DCF model variants generally incorporate broad consideration of specific risk factors, which is represented by the proxy group.[250] Because all risk factors are incorporated into the DCF analysis, the resulting ROE will be the average of the results of the two variants.[251]

173. Regulated utility companies generally have low risk because they have dedicated streams of revenue from set utility rates.[252] Other risk mitigation factors include the use of cost-recovery riders, such as those used by Applicant.[253]

174. When using the CAPM analysis, 20-year treasury bonds should be used as a data point because they have a lower interest risk than 30-year treasury bonds.[254] Use

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[243] Ex. 606 at Schedule 5 (Amit Surrebuttal).
[244] *Id.* at 20-21.
[245] Ex. 606 at 10-11 (Amit Surrebuttal).
[246] *Id.* at 16; Evidentiary Hearing Tr. Vol. 3 at 236-37 (Amit).
[247] Ex. 606 at 16 (Amit Surrebuttal).
[248] *Id.*
[249] *Id.*
[250] Ex. 501 at 20 (Lebens Direct).
[251] *Id.*
[252] Ex. 504 at 21 (Lebens Surrebuttal).
[253] *Id.*
[254] Ex. 606 at 18 (Amit Surrebuttal).

of 30-year treasury bonds will bias the ROE upwards.[255] Current rather than expected yields should be used in order to best represent investors' current expectations.[256]

175. Stability of investor expectations over time cannot be assumed when using the Risk Premium analysis.[257]

176. Flotation costs are incorporated into the DCF model, but not other models where flotation costs must be added.[258]

IV. RATE DESIGN

A. Class Cost of Service Study (CCOSS)

177. In Docket No. E015/GR-09-1151, the PUC issued four orders related to class cost of service study (CCOSS) for Applicant to comply with in its next rate case.[259]

178. Applicant complied with the PUC's four orders (Order Points 20, 21, 22, and 23).[260]

179. The CCOSS results at the class level show the class cost revenue requirement outcomes and indicate the change from present rate revenues required for each class to provide equal rates of return on investment.[261]

180. Considering demand, energy, and customers for each class level, the class cost revenue requirements resulting from the CCOSS are an appropriate starting point for rate design.[262]

i. Fixed Production Cost Classification

181. Fixed production revenue requirement items consist of all fixed costs and associated offsetting revenues that do not vary with electricity production at the time it is produced.[263]

182. Applicant seeks to have its fixed production costs classified as 100 percent demand-related.[264]

ii. CCOSS Model and Allocation Methods

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[255] *Id.*
[256] *Id.* at 19.
[257] Ex. 601 at 51-52 (Amit Direct).
[258] Ex. 501 at 22-23 (Lebens Direct); Ex. 34 at 27 (Hevert Direct); Ex. 604 at 17-18 (Amit Rebuttal).
[259] Ex. 78 at 4 (Shimmin Direct).
[260] *Id.* at 4-8, SLS-1, SLS-2 (Shimmin Direct).
[261] *Id.* at 10.
[262] *Id.*
[263] Ex. 610 at 9 (Collins Direct).
[264] Ex. 81 at 3-4 (Shimmin Rebuttal).

183. Applicant uses a Peak & Average (P&A) allocation method.[265]

184. P&A methodology allocates fixed production and transmission costs to a class based on an allocation factor that is composed of two parts: (1) an average demand or energy and (2) a coincidental peak.[266]

185. Applicant used the 2016 Advance Forecast Report to calculate the number of customers and billing units for total revenue classes.[267]

186. Applicant has improved the linkages between its CCOSS and financial information filing by matching all adjustments identified in financial schedules with properly marked data in the CCOSS.[268]

187. Five additional cost allocation methods were tested to attempt to confirm the outcome of the P&A method.[269] Those methods were: the single coincident peak method (1CP); the average 12-month coincident peak method (12CP); the three-winter-month peak method (3WCP); the three-summer-month peak method (3SCP); and a combination of the 3WCP and 3SCP (3W3SCP).[270]

188. The cost allocation methods produced a wide variety of results for the 2017 test year. For example, the change in revenue necessary to bring residential customers to their cost of service ranged from a high of $54.4 million (1CP) to a low of $35.7 million (P&A). The change necessary for large power customers ranged from a high of $12.2 million to a low of negative $10.8 million.[271]

iii. Functionalization of 46kV Lines

189. Power lines operating at greater than 30kV are typically accounted for (functionalized) as transmission lines (lines that move electricity from the plant to the distribution system at a substation).[272] Conversely, power lines operating at less than 40kV are typically functionalized as distribution lines (lines that move electricity from the transmission system to the customer).[273]

190. In the early 2000's Applicant was involved in a study conducted by the PUC, the *Boundary Guidelines* Docket No. E999/CI-99-1261, which examined and developed guidelines for the functionalization of transmission and distribution lines[274]

[265] Ex. 78 at 12-13 (Shimmin Direct).
[266] *Id.*, SJS-1 at 8.
[267] Ex. 82 at 53 (Podratz Direct).
[268] *Id.*
[269] Ex. 78 at 11-13 (Shimmin Direct).
[270] *Id.* at 11.
[271] *Id.* at 13.
[272] Ex. 81 at 21-22 (Shimmin Rebuttal).
[273] *Id.*
[274] *Id.* at 22.

191. In 2002, the PUC reviewed and approved Applicant's classification of its 46kV system as distribution.[275]

iv. Classification of Distribution System

a. Meters

192. Since 2009, Applicant has been purchasing and installing advanced metering infrastructure (AMI) meters.[276] The AMI meters provide several benefits, including: efficient deployment of advanced time-based customer rate offerings, outage notifications, notification of service issues, improved load control, more frequent customer usage data, fewer estimated bills for customers, and remote reconnection following a disconnect.[277]

193. Applicant classifies and allocates its meters as 100 percent customer costs.[278]

b. Other Distribution Assets

194. FERC accounts 364 through 369 consist of poles, overhead distribution lines, underground distribution lines, overhead and underground transformers, and costs for service lines.[279]

195. Applicant classifies and allocates these distribution assets as 13.4 percent demand and 86.6 percent customer components.[280]

B. Revenue Apportionment

196. Revenue apportionment is the rate design process of dividing a utility's revenue requirement among its customer classes.

197. In addition to revenue requirements by customer class from the CCOSS, a utility also considers factors such as rate stability, overall customer billing impacts, and the benefits of sending appropriate price signals to customers.[281]

198. Applicant proposes that the residential class rates increase between 13 and 15 percent, but in no case less than five percent.[282]

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[275] *In re Pet. by Minn. Power for Approval of Asset Separation and Accounting Methodology*, MPUC Docket No. E015/M-01-1416, Order Approving Petition, With Clarifications and Requirements at 2 (Aug. 8, 2002).
[276] Ex. 49 at 64 (Fleege Direct); Ex. 509 at 37(Nelson Direct).
[277] Ex. 49 at 65 (Fleege Direct).
[278] Applicant Initial Br. at 142 (Sept. 12, 2017) (eDocket No. 20179-135459-02); Ex. 509 at 37 (Nelson Direct).
[279] Ex. 81 at 26 (Shimmin Rebuttal); Ex. 611 at 22-23 (Collins Rebuttal).
[280] Ex. 8, Sched. O-1 at 29 (Application, Vol. 5 Workpapers); Ex. 81 at 26 (Shimmin Rebuttal); Ex. 611 at 29 (Collins Rebuttal).
[281] Ex. 82 at 52, 54 (Podratz Direct).
[282] Ex. 86 at 23, 24 (Podratz Rebuttal); Evidentiary Hearing Tr. Vol. 2 at 99 (Podratz).

199. Applicant proposes no change to the lighting class rates.[283]

200. Applicant proposes duel fuel service customer class rate increase the same as the overall retail rate increase.[284]

201. Applicant proposes that the rates for general service, large light and power, large power, and municipal pumping classes increase evenly, on a percentage basis, as necessary to recover each class's deviation from the CCOSS.[285]

C. Residential Service Charge

202. The residential service charge is intended to cover some of the connection costs incurred by Applicant to connect residential dwellings to utility service.[286]

203. Applicant seeks an increase of the residential service charge from $8.00 to $9.00 to get closure to its claimed residential customer-related service connection cost of $26.35 per month.[287]

D. Block Rate Design

204. Prior to Applicant's 2009 rate case, its residential rates included three energy blocks.[288] However, in 2009 the PUC required Applicant to adopt a five-block rate design with inverted block rates that increase for higher quantities of energy usage.[289] The goal of the new block rate system was to reduce electric bills for residential customers with the low usage while also providing an incentive for conservation for residential customers with high usage.[290]

205. Applicant began billing residential customers under the five-block rate structure on June 1, 2011.[291]

206. As part of this proceeding, Applicant proposes to eliminate the five-block rate system required as part of the 2009 rate case and implement a two-block rate structure.[292]

E. CARE Program

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283 Ex. 86 at 24.
284 *Id.*
285 *Id.*
286 Ex. 82 at 60-61.
287 *Id.* at 60; Ex. 6, Sched. E-2 at 104 (Application Vol. IV).
288 Ex. 82 at 57 (Podratz Direct).
289 *Id.*
290 *Id.*
291 *Id.* at 58.
292 *Id.* at 58-59.

207. Applicant's pilot rider for customer affordability of electricity (CARE) provides discounted rates to qualified low-income residential customers.[293]

208. The program is funded by an affordability surcharge assessed to other customers.[294]

209. CARE program discounts and surcharges are tracked and adjusted as necessary between rate cases.[295]

210. In this rate case, Applicant proposes to revise the "RATE MODIFICATION" section of the CARE Rider. Applicant will specify Customer/Service Charge and Energy Charge discounts instead of the existing CARE Customer Charge and Energy Charges that replace the standard Residential Service Charge and Energy Charges. Applicant will make minor changes to the Affordability Surcharge terminology of the CARE Rider, changing it to the more-descriptive "Low-Income Affordability Program Surcharge."[296]

F. Large Power Interruptible Product

211. Applicant did not propose changes to its Large Power Interruptible Service Rider.[297]

G. Large Power Incremental Production Rider

212. Incremental production service (IPS) is designed to encourage customers to increase production above historical levels without being subject to additional contractual demand commitments.[298] For measured demand in excess of the Incremental Production Service Threshold (IPST) established in each ESA, the customer's demand is not subject to demand charges or demand ratchet provisions.[299]

213. Applicant proposes to increase its Large Power IPS energy usage limit from the current 110 percent limit to 120 percent of each large power customer's IPS threshold.[300]

214. Applicant's proposal reduces energy supply costs for many customers because IPS is served with the highest-cost energy on the system, and the cost of the energy is excluded from the firm supply used to determine the fuel clause cost for firm retail sales. As a result, the average cost for firm energy to all customers is reduced.[301]

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293 *Id.* at 37-38.
294 *Id.*
295 *Id.*
296 *Id.* at 61-62.
297 LPI proposed a revised rider for Large Power Interruptible Service. Ex. 104 at 10 (Stephens Direct).
298 Ex. 82 at 71 (Podratz Direct).
299 *Id.*
300 *Id.* at 71-72; Ex. 86 at 35-37 (Podratz Rebuttal); Ex. 87 at 13-14 (Podratz Surrebuttal).
301 Ex. 86 at 36 (Podratz Rebuttal); Ex. 87 at 14 (Podratz Surrebuttal).

H. Large Light and Power Time-of-Use Rider

215. In the 2009 rate case, the PUC required Applicant to develop a Time-of-Use (TOU) tariff for the Large Light and Power (LLP) customer class.[302]

216. No customers are currently taking advantage of the TOU tariff.[303]

217. In order to encourage LLP customers to use the TOU tariff, Applicant proposes to increase the on-peak rate by approximately the same percent as the overall rate increase for the standard LLP service schedule.[304]

218. If LLP customers take advantage of the TOU tariff, the on- and off-peak periods of usage will flatten out – a benefit to the overall electric system by making it more efficient.[305]

I. Back-up Generation Rider

219. Applicant's Back-up Generation program was approved by the PUC in 2015.[306]

220. Applicant would own, install, and maintain a diesel or natural gas generator at participating customer sites.[307] The generators will have better emission performance than those typically used in a commercial setting.[308]

221. Back-up generators will be called into service, when necessary, during peak loads to support the reliability of the grid.[309]

222. Customers can rely on the back-up generator to avoid extended interruptions during outages.[310]

223. Participating customers will pay a monthly fee, and their overall cost for the back-up generator will be less than the cost they would incur purchasing and installing their own.[311]

224. The Program is designed to serve general service, large light and power, and municipal pumping customers with a load profile of 250 kW to 1 MW.[312]

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[302] Ex. 82 at 66 (Podratz Direct).
[303] *Id.*
[304] *Id.* at 67.
[305] Ex. 107 at 11 (Gorman Direct).
[306] Ex. 71 at 11 (Pierce Rebuttal); *In re Minn. Power's Application for Approval of its 2015-2019 Res. Plan,* MPUC Docket No. E015/RP-15-690, Integrated Resource Plan at Appendices J, K (Sept. 1, 2015).
[307] Ex. 67 at 39 (Pierce Direct).
[308] *Id.* at 40.
[309] *Id.* at 39-40.
[310] *Id.*
[311] *Id.*
[312] Ex. 67 at 39 (Pierce Direct); Ex. 71 at 11 (Pierce Rebuttal).

225. Applicant proposes to allocate the costs of the Back-up Generation program to all customers because the program benefits the system as a whole during peak periods.[313]

J. Green Pricing Program

226. Applicant proposes to modify its Rider for Residential/General Electric Service Renewable Energy to develop a Green Pricing Program where customers can choose to get between 25 percent and 100 percent of their electricity from renewable energy.[314]

227. To cover the costs of the Green Pricing Program, Applicant wants to charge customers who opt into the program: (1) a certification fee, (2) an administration fee, and (3) the cost of the renewable energy purchased, plus the cost of fuel for Applicant's traditional generation plants.[315]

K. Reconnect Pilot

228. Applicant proposes to begin a new pilot program that permits the reconnection of electric service remotely for customers who have been disconnected as a result of non-payment.[316]

229. Applicant can remotely reconnect a customer's electric service using advanced metering infrastructure (AMI).[317]

230. Applicant proposes a pilot program because not all customers have AMI yet, and Applicant seeks to learn about the customer experience remote reconnection will provide, its scalability and effectiveness, operational savings, technology and administrative costs, and safety benefits.[318]

231. The fee for reconnection under the pilot would be $20 at all times, as compared to the current $100 reconnect fee after business hours and on weekends and holidays.[319]

232. The pilot program would be offered to approximately 200 residential customers throughout Applicant's service territory, mostly within Duluth and Cloquet.[320] Customers will be selected based on likelihood of disconnection.[321]

[313] Ex. 71 at 9, 11 (Pierce Rebuttal).
[314] Ex. 76 at 11-12 (Koecher Direct).
[315] *Id.* at 16; Ex. 77 at 9 (Koecher Rebuttal).
[316] Ex. 76 at 19 (Koecher Direct).
[317] *Id.* at 19-21.
[318] Ex. 76 at 21 (Koecher Direct).
[319] *Id.* at 20.
[320] *Id.*
[321] *Id.* at 20-21.

L. GRID Pilot

233. Applicant proposes the GRID pilot program in order to establish a framework and modest funding source to test the abilities, costs, and benefits of new technologies in a measured, scalable way.[322] Applicant also wants to use a rider designed to enhance transparency and provide flexibility necessary to advancing grid modernization.[323]

234. Applicant wants to include a stakeholder advisory committee and governance model to oversee the test project selection process, project review, and status updates.[324] The committee would also support annual compliance reporting, including an update on funding status, project progress, and evaluative findings.[325]

235. Applicant proposes $2.7 million be raised annually through the rider, which could be incorporated into the current Resource Adjustment line on customer bills.[326]

236. Residential customers would pay, on average, $7.43 per year, or $.62 per month, for the GRID pilot.[327] While low-income customers would be included in the GRID pilot program, the costs for the program would not be recovered from low-income (LIHEAP-eligible) customers.[328]

M. Credit Card Fees[329]

237. Currently, Applicant's customers are individually charged $2.95 when they use a debit or credit card.[330]

238. Applicant uses a third-party vendor for processing debit and credit card payments.[331]

239. Applicant proposes to shift the cost of debit and credit card transactions to all ratepayers, similar to the costs for other kinds of payment transactions such as check and Automatic Clearing House (ACH) payments.[332]

240. Customers, in general, are unhappy with being specifically charged fees for using modern common payment mechanisms such as prepaid debit cards and credit cards.[333]

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[322] Evidentiary Hearing Tr. Vol. 1 at 204 (Koecher).
[323] Ex. 76 at 25-28 (Koecher Direct).
[324] *Id.* at 27-28.
[325] *Id.* at 18.
[326] *Id.* at 16.
[327] *Id.*
[328] *Id.* at 19.
[329] *See* Findings of Fact 53 - 57.
[330] Ex. 76 at 28 (Koecher Direct).
[331] *Id.*
[332] *Id.*
[333] *Id.* at 29-30; Ex. 77 at 22-23 (Koecher Rebuttal); Tr. Vol. 1 at 204 (Koecher).

241. Applicant intends to continue to use the same third-party vendor to process the debit and credit card payments at the current charge per transaction, with hopes that the cost per transaction will decrease.[334] Applicant wants to shield itself from the risk of processing such payments by using the vendor.[335]

N. Annual Rate Review Mechanism (ARRM)

242. Applicant proposes to implement an annual rate review mechanism (ARRM) that would provide for potential rate adjustments between rate cases when changes in sales or other factors result in significant increases or decreases (more than .50 basis points, or .5 percent) in Applicant's actual ROE compared to its authorized ROE.[336]

243. Customers would be protected by a limit to changes in O&E expenses to a maximum of three percent annual escalation above the level allowed for the 2017 test year.[337]

244. Rate increases would be capped at five percent annually and rate increases would be limited to three consecutive years. There would be no limit on potential rate decreases.[338]

245. The ARRM would function for no more than five years.[339]

246. Applicant proposes to submit annual compliance filings, including a CCOSS and calculation of actual jurisdictional ROE for the previous year, as a basis for determining whether a rate adjustment is needed.[340]

247. The proposal does not include performance metrics aligned with customer needs or benefits.[341]

248. From 1996 through 2016 Applicant's actual ROE has out-performed its allowed ROE by more than half a percent on five annual occasions (1998, 1999, 2001, 2005, and 2007).[342] During that same period, Applicant's actual ROE underperformed its allowed ROE by more than half a percent on ten annual occasions (2003, 2004, 2008, 2009, 2010, 2012, 2013, 2014, 2015, and 2016).[343] The remaining years the actual ROE performed within plus or minus a half percentage point of the allowed ROE.[344]

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334 Ex. 77 at 23-24 (Koecher Rebuttal).
335 *Id.*
336 Ex. 82 at 92-93 (Podratz Direct).
337 *Id.*; Ex. 83 at 43 (Podratz Rebuttal).
338 Ex. 82 at 93 (Podratz Direct); Ex. 83 at 43-44 (Podratz Rebuttal).
339 Ex. 82 at 94 (Podratz Direct); Ex. 83 at 43 (Podratz Rebuttal).
340 Ex. 82 at 93, 95 (Podratz Direct).
341 Ex. 83 at 50 (Podratz Rebuttal).
342 *Id.*, MAP-R-12.
343 *Id*.
344 *Id*.

V. EFFECT OF STANDARD TARIFFS, ELECTRIC SERVICE AGREEMENTS, AND THE EITE CREDIT ON EXPECTED REVENUE FROM INDUSTRIAL CUSTOMERS

A. U.S. Steel Electric Service Agreement (ESA)

249. Applicant and U. S. Steel reached an agreement on a proposed Amended and Restated ESA that defines the terms under which Applicant provides electric service to U. S. Steel's Minnesota Taconite (Minntac) and Keewatin Taconite (Keetac) facilities.[345]

250. The Amended ESA was largely approved by the PUC on December 29, 2016, and incorporated into this proceeding for a determination on whether the remaining provision is in the public interest.[346] The remaining provision is a credit applicable when both Minntac and Keetac are both operating.[347]

251. The credit is an incentive to increase operation levels at both facilities.[348]

252. Increased levels of production at both Minntac and Keetac allows fixed costs to be spread over increased energy sales, resulting in lower electric rates and providing an economic boost to the region.[349]

253. The parties do not dispute the proposed provision in the U.S. Steel ESA.[350]

B. EITE Credit

254. In 2015, the Minnesota Legislature enacted a law allowing a utility to propose EITE rates for companies that use high amounts of energy and operate in highly competitive markets.

255. In November 2015, Applicant filed a petition with the PUC requesting EITE rates for eligible customers.[351] The PUC denied the petition in March 2016.[352]

256. In June 2016, Applicant filed a revised petition with the PUC (Docket 15-564) for approval of an EITE rate schedule that would provide specified customers a

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[345] Ex. 62 at 1 (Perala Supplemental Direct).
[346] *Id.*; *In re Pet. by Minn. Power for Approval of an Amended and Restated Elec. Serv. Agreement between U.S. Steel Corp. and Minn. Power*, MPUC Docket No. E015/M-16-836, Order Approving In Part Proposed Electric Service Agreement, Referring Matter to Rate Case, and Closing Docket (Dec. 29, 2016).
[347] Ex. 62 at 1 (Perala Supplemental Direct); *In re Pet. by Minn. Power for Approval of an Amended and Restated Elec. Serv. Agreement between U.S. Steel Corp. and Minn. Power*, MPUC Docket No. E015/M-16-836, Order Approving In Part Proposed Electric Service Agreement, Referring Matter to Rate Case, and Closing Docket (Dec. 29, 2016).
[348] *See* Ex. 62 (Perala Supplemental Direct).
[349] *Id.* at 9.
[350] Ex. 609 at 9 (Rakow Surrebuttal).
[351] Ex. 40 at 24 (Minke Direct); *In re Pet. to Ensure Competitive Electric Rates for Energy-Intensive Trade-Exposed Customers*, MPUC E015/M-15-984, Pet. of Minn. Power (Nov. 13, 2015).
[352] Ex. 40 at 24 (Minke Direct).

discount based upon each customer's site peak electric usage and total energy consumption.[353]

257. In December 2016, the PUC approved Applicant's EITE rate schedule as applied to eleven of Applicant's industrial customers.[354]

258. In Docket 15-564, the maximum allowable energy charge credit for Applicant's eleven customers was set by the PUC at $19.2 million per year based upon estimated full production rates of the customers, representing a 5% decrease in the cost of electricity to the customers.[355]

259. Use of EITE rates impacts the calculation of Applicant's sales revenues this proceeding used to set the rate base.[356]

260. As of early April 2017, the parties were aware that U.S. Steel was resuming operations at Keetac and higher revenues associated with Applicant's sales of electricity to Keetac would offset the effects of the EITE surcharge.[357]

261. Any conclusion of law more properly designated as a finding of fact is deemed as such. Any material fact included in the attached memorandum that is not already reflected in the findings of fact is hereby incorporated as a finding of fact.

Based upon these findings of fact, the Administrative Law Judge makes the following:

CONCLUSIONS OF LAW

1. The Public Utilities Commission and the Administrative Law Judge have jurisdiction to consider this matter pursuant to Minn. Stat. §§ 14.50, 216B.08 (2016).

2. The public and the parties received proper and timely notice of the hearings. Applicant complied with all procedural requirements of statute and rule.

3. Every rate set by the Commission shall be just and reasonable.[358] Rates must not be unreasonably preferential, prejudicial, or discriminatory, and must be sufficient, equitable and consistent in application to a class of consumers.[359] To the maximum reasonable extent, rates must be set to encourage energy conservation and

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[353] *Id.* at 24-25; *In re Pet. to Ensure Competitive Electric Rates for Energy-Intensive Trade-Exposed Customers*, MPUC E015/M-15-564, Revised Pet. of Minn. Power at 3 (June 30, 2016).
[354] *In re Pet. to Ensure Competitive Electric Rates for Energy-Intensive Trade-Exposed Customers*, MPUC E015/M-15-564, Order Approving EITE Rate, Establishing Cost Recovery Proceeding, and Requiring Additional Filings at 12 (Dec. 21, 2016).
[355] *Id.* at 14.
[356] *See* Ex. 43 at 3 (Minke Surrebuttal); Ex. 632 at 34-35 (Lusti Surrebuttal).
[357] Ex. 632 at 35-37 (Lusti Surrebuttal).
[358] Minn. Stat. § 216B.03 (2016).
[359] *Id.*

renewable energy use, as well as public policy goals in Minn. Stat. §§ 216B.164, .241, and 216C.05 (2016).[360]

4. The burden of proof is on Applicant to show the proposed rate change is just and reasonable.[361] Any doubt as to reasonableness should be resolved in favor of the consumer.[362]

I. TEST YEAR

A. Average Rate Base

i. Boswell Energy Center

5. Depreciation is to be based on "the estimated useful life of the unit . . . in a systematic and rational manner."[363]

6. There are no particular restrictions on the consolidation of assets for accounting purposes. A "unit" may consist of a group of units under PUC rules.[364]

7. Given the varied estimated useful lives of the units that make up the BEC (2024, 2034, and 2035), there is not a rational basis to group them all together. Thus, consolidation of all units at the BEC for accounting purposes is not recommended.

8. BEC1 and BEC2 should be depreciated until 2022.

9. BEC3, BEC4, and the common facilities should be depreciated until 2035, the current maximum approved life of any of the three units.

ii. Transmission Capital Projects

10. The Administrative Law Judge concludes that Applicant has demonstrated that inclusion of its final list and value of capital transmission projects in the test year rate base is appropriate. Any recalculation should be made, in part, based on Applicant's claimed costs of those projects.

iii. Generation Capital Projects

11. The Administrative Law Judge concludes Applicant has demonstrated that its final list of proposed generation capital additions and the costs of those projects are reasonable. Applicant should have updated the revenue requirement numbers based on the change in the value of the proposed generation capital projects, but the amount of change is so small that it does not prejudice ratepayers in any aggregate sense. Thus,

[360] *Id.*
[361] Minn. Stat. § 216B.16, subd. 4.
[362] Minn. Stat. § 216B.03.
[363] Minn. R. 7825.0500, subp. 7 (2017).
[364] *Id.*

the failure to change the total costs based on the postponed and replacement projects in the rate base is not unreasonable and a change, is not necessary.

iv. Storm Damage Amortization Expense

12. The Administrative Law Judge concludes that the test year average should be recalculated without the inclusion of the $732,272 annual amortization expense.

v. Storm Restoration Budget

13. The Administrative Law Judge concludes a bright line test for considering the addition of test year costs after the initial filing is not warranted. Instead, a case-by-case approach when addressing with such requests is more appropriate.

14. The Administrative Law Judge further concludes that the addition of $1.68 million for storm expenses should be excluded from the test year expenses because the request: (1) was untimely, (2) was based on an unusual storm year; and (3) the PUC previously rejected Applicant's attempt to recover claimed storm damage costs.

vi. Sappi/Cloquet Generator Amortization Expense

15. The test year rate base should be recalculated, in part, because Applicant has removed the $232,618 deferred amortization expense from the test year rate base.

vii. Credit Card Processing Fees

16. Applicant has not provided clear evidence on the cost savings supporting its proposal to shift credit and debit card fees from some customers to all customers.

17. Therefore, the Administrative Law Judge rejects Applicant's request to include $350,000 into the 2017 test year base rates for the purpose of covering the costs of credit and debit cards fees. Instead, the Administrative Law Judge recommends that $175,000 be included in the 2017 test year base rates and require Applicant to thoroughly explore efficient payment mechanisms.

viii. Charitable Contributions and Administrative Costs of Minnesota Power Foundation

18. Minn. Stat. § 216B.16, subd. 9 (2016), allows 50 percent of charitable contributions by a utility to be considered operating expenses. The charitable contributions must qualify under Minn. Stat. § 300.66, subd. 3 (2016).

19. Applicant's use of a three-year average to calculate the amount of charitable contributions for the 2017 test year is entirely reasonable and consistent with the PUC's directive of November 2, 2010, when it required Applicant to use a three-year average rather than a single year.

20. Applicant has demonstrated that recovery of $394,280 for charitable donations during the test year is appropriate.

21. Minn. Stat. § 216B.16, subd. 9 (2016), is silent regarding a utility's administrative costs for charitable giving.

22. The PUC has determined that when an applicant "has not demonstrated that it is reasonable or consistent with the public interest to charge the Foundation's administrative costs to ratepayers as a part of the cost of furnishing electric service," such costs are excluded in favor of the consumer.[365]

23. Applicant has not demonstrated that recovery of 100 percent of the costs of administering charitable donations is appropriate. The Administrative Law Judge concludes that recovery of $57,298, or 50 percent, of the administrative costs is appropriate

ix. Travel, Entertainment, and Related Employee Expenses

a. Membership Dues

24. Pursuant to Minn. Stat. § 216B.16, subd. 17(a)(6) (2016), a utility may recover reasonable and necessary dues and expenses for memberships in organizations or clubs.

25. In June 1982, the PUC issued a non-binding statement of policy on how utilities are to assist it in evaluating dues expenses.[366] The PUC stated that a utility cannot "impose on customers the expense of dues when it has not been shown that customers receive any benefit from the organization receiving the dues[.]"[367]

26. Applicant met its burden of proof with regard to the membership dues for Edison Electric Institute National Hydropower Association, and Western Coal Traffic League, for a total amount of $417,946.

27. Applicant failed to meet its burden of proof with regard to the remainder of claimed membership dues because it did not provide the rationale for membership in each organization for the company or employees. Thus, $808,043 should be excluded from the 2017 test year.

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[365] *In re Application of N. States Power Co., a Minn. Corp., for Auth. to Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E002/GR-08-1065, Findings of Fact, Conclusions of Law and Order at 23 (Oct. 23, 2009).
[366] Ex. 8, Part 3 of 8, ADJ-IS-15 (Initial Filing Vol. 5).
[367] *Id.*

b. Employee Gifts

28. Pursuant to Minn. Stat. § 216B.16, subd. 17(a), a utility is authorized to recover employee gifts if the expenses are reasonable and necessary for the provision of utility service.

29. Applicant provided evidence of valid reasons for employee gifts of all sorts, including safety awards, service and retirement awards. The evidence demonstrates that the purpose of the gift expenses was to support the provision of safe utility service at reasonable cost by supporting employee retention and rewarding, if not at least recognizing, longevity of employee service.

30. The necessity and reasonableness of the expense of $23,007 for employee gifts has been established. The Administrative Law Judge concludes that the amount should be included in the test year rate base.

c. Remaining Expenses

31. Minn. Stat. § 216B.16, subd. 17(b) (2016), expressly requires itemization for every employee expense that a utility requests to be recovered from ratepayers.

32. While a utility may use "standard accounting reports already utilized by the utility[,]" the reports must include itemization information required by statute, including the business purpose and vendor paid for each expense.[368]

33. The Administrative Law Judge concludes that Applicant's method of calculating travel, entertainment, and related employee expenses is appropriate.

34. Applicant failed to demonstrate it met statutory requirements when it did not include the data necessary for every itemization. Where the vendor is not identified, or is only listed as the employee, and there is insufficient data to clearly indicate the business purpose of the expense, the itemized expense should not be permitted.

x. Prepaid Pension Asset

35. In a recent case, the PUC rejected a request to recover a prepaid pension asset because it is virtually impossible to discern whether the changes in value come from shareholder dollars, marketplace returns, or changes in actuarial accounting.[369]

36. The Administrative Law Judge concludes that the prepaid pension asset should not be included in the 2017 test year rate base.

[368] *In re Application of Otter Tail Power Co. for Auth. to Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E017/GR-15-1033, Findings of Fact, Conclusions, and Order at 45, 47 (May 1, 2017).
[369] *In re Application of Otter Tail Power Co. for Auth. to Increase Rates for Elec. Serv. in Minn.,* MPUC Docket No. E017/GR-15-1033, Findings of Fact, Conclusions of Law, and Order at 25 (May 1, 2017).

xi. High-level Employee Related Expenses

37. “Barring excessive compensation levels, skewed incentives, or other public policy concerns, the Company has the discretion to structure its compensation packages in accordance with its best business judgment.”[370]

38. Compensation and benefits is always a factor for potential and current employees of a business.[371]

39. Applicant has shown that a large percentage of companies its size, including 17 utility companies, provide management-level employees with non-qualified pension benefits as part of their compensation.

40. Applicant has met its burden to prove that inclusion of the high-level employee related expenses in the test year is reasonable.

xii. Unfilled Positions

41. With the $2,969,621 adjustment, Applicant’s request to recover its employee compensation expense at part of the 2017 test year is reasonable.

xiii. Test Year Cash Working Capital (CWC)

42. Applicant’s proposed lead/lag study and resultant CWC adjustment are consistent with prior PUC determinations and therefore reasonable.[372]

43. Applicant’s CWC must be updated based on final adjustments made in this docket and then incorporated into final rates.

44. Because the actual level of the interest synchronization adjustment is dependent on the final outcome of rate base and interest adjustments, Applicant should be required to recalculate the adjustment as part of its final compliance filing to reflect final rate outcomes in this proceeding.

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[370] *In re Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E-015/GR-09-1151, Findings of Fact, Conclusions, and Order at 29 (Nov. 2, 2010).

[371] *In re Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E-002/GR-12-961, Findings of Fact, Conclusions of Law, and Recommendations at 42 (July 3, 2013) (“[t]o provide safe and reliable service, the Company needs to be able to offer competitive compensation packages to its employees.”).

[372] *See in re Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E-015/GR-09-1151, Findings of Fact, Conclusions, and Order at 71 (Nov. 2, 2010); *in re Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, MPUC Docket No. E002/GR-15-826, Findings of Fact, Conclusions, and Order at 14, 66 (June 12, 2017).

xiv. Production Tax Credits and Prorated Accumulated Deferred Income Taxes

45. The Administrative Law Judge concludes that the Department's and Applicant's agreement that final rates do not need to reflect prorated ADIT in order to avoid a tax normalization violation is reasonable. Use of a prorated ADIT for the interim to avoid a tax normalization violation is likewise reasonable.[373]

46. The Administrative Law Judge concludes that Department's and Applicant's agreement to use the PTC rate of $24/MWh is reasonable and that the resulting changes to the calculation of the rate base, increasing it by $731,243, is also reasonable.

xv. Fuel Clause Adjustments

a. Fuel Clause Adjustment Methodology

47. The Administrative Law Judge concludes that Applicant's request is reasonable. If a determination is made in Docket E999/CI-03-803 prior to a final determination in this rate case, Applicant should submit new calculations based on the fuel clause adjustment methodology used in Docket E999/CI-03-803.

b. Fuel Clause Transition Cost Recovery

48. Applicant's request to delay a determination on its request for a fuel cost recovery delay amount, pending a possible change to the fuel clause adjustment methodology, is reasonable.

c. Base Cost of Fuel

49. The Administrative Law Judge concludes that Applicant's request that a determination be deferred to Docket E999/CI-03-803 is reasonable.

d. Chemical and Reagent Costs

50. Minn. Stat. § 216B.16, subd. 7(4) (2016), permits recovery of reagent and chemical costs through a fuel clause adjustment rider. However, the PUC has not promulgated rules for recovery of reagent and chemical costs.

51. The PUC has held that allowing recovery of all reagent and chemical costs through a fuel clause would not be reasonable without careful review and would like to reduce a utility's incentive for efficiency and cost minimization.[374]

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[373] Evidentiary Hearing Tr. Vol. 1 at 197–99 (Jago).
[374] *In re Application of Otter Tail Power Co. for Auth. To Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E017/GR-15-1033, Findings of Fact, Conclusions, and Order at 32 (May 1, 2017).

52. Applicant's request for recovery of reagent and chemical costs should be denied.

e. Business Interruption Insurance

53. Minn. Stat. § 216B.16, subd. 7 (2016), does not include or anticipate business interruption insurance being recovered as part of a fuel clause adjustment rider.

54. PUC rules also do not include recovery of business interruption insurance by a utility.

55. Applicant's request for recovery of business interruption insurance premiums should be denied.

f. Nitrous Oxide Allowances

56. Minn. Stat. § 216B.16, subd. 7, does not include or anticipate debiting or crediting nitrous oxide allowances as part of a FCA rider.

57. PUC rules also do not include or anticipate debiting or crediting nitrous oxide allowances as part of a FCA rider by a utility.

58. Applicant's request for debiting and crediting NO_x allowances as part of its FCA rider should be denied.

xvi. Generation O&M: Supervision and Engineering Expenses and Meter Reading Expenses

59. To determine whether Applicant's budget is just and reasonable requires a determination about "whether the ratepayers or shareholders should bear those costs."[375]

60. The standard of proof, a preponderance of the evidence, requires the tribunal to consider "whether the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility considered together with the Commission's statutory responsibility to enforce the state's public policy that retail customers of utility services shall be furnished such services at reasonable rates."[376]

61. Applicant's proposed budget for generation O&M supervision and engineering expenses and meter reading expenses in the 2017 test year is just and reasonable.

[375] *Pet. of N. States Power Co.*, 416 N.W.2d 719, 722-23 (Minn. 1987).
[376] *In re Minn. Power & Light Co.*, 435 N.W.2d 550, 554 (Minn. Ct. App. 1989) (quoting *In re Pet. of N. States Power Co.*, 416 N.W.2d 719, 722 (Minn. 1987)).

xvii. Sales Forecast – Keetac

62. Applicant validly relies on nine months of production in 2017 at Keetac, not for the sake of forecasting actual Keetac production, but to forecast the total production of all of Applicant's taconite producing customers.

63. Based on the most recent ten-year average for Applicant's taconite producing customers of 89 percent utilization, Applicant's forecast of 90 percent for the 2017 test year is reasonable.

xviii. Taconite Harbor Re-Start/Re-Idle

64. Applicant has demonstrated, by a preponderance of the evidence, that it will likely incur at least $1.25 million in costs to re-start and re-idle THEC units 1 and 2 during each of the next four years, including the test year.

65. Applicant's request to include $ 1.25 million for the costs of one re-start and re-idle in the 2017 test year is just and reasonable.

xix. Solar Energy Standard (SES) Capacity Benefits

66. Applicant's proposed method of calculating the value of solar capacity, based on the clearing price for capacity in MISO's annual Planning Resources Auction in Local Resource Zone 1, is reasonable and appropriate.

II. PROPOSED CAPITAL STRUCTURE AND RETURN ON EQUITY

67. Applicant bears the burden of proving, by a preponderance of the evidence, that its proposed return on investment, which derives from the ROE, capital structure, and debt, is fair and reasonable.[377]

68. The return on investment "should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties."[378]

69. The Administrative Law Judge concludes that Applicant's use of multiple models, its particular screening of companies to create a proxy list, and the subjective evaluation by the analyst, is unjust and unreasonable. As a result, the resulting proposed capital structure and ROE may be unjust and unreasonable.

[377] Minn. Stat. § 216B.16, subds. 4, 6 (2016).
[378] *Bluefield Waterworks & Imp. Co. v. Public Service Commission*, 262 U.S. 679, 693 (1923).

70. DCF model inputs are more objective and the model workings are more transparent and generate more consistent outcomes than other models.[379]

71. The Administrative Law Judge concludes that the Department's proxy list should be used to run the analytical model. No additional screening or subjective analysis should be employed.

72. The Administrative Law Judge concludes that the DCF model should be used to determine the ROE and capital structure in this matter.

73. The Administrative Law Judge concludes that the resulting ROE should be the midpoint of the range developed by the two DCF variants, without additional subjective analysis.

III. RATE DESIGN

74. The rate design process is quasi-legislative in nature.[380] The PUC must balance a wide range of concerns, including: "economic efficiency, continuity with prior rate cases; ease of understanding; ease of administration; promotion of conservation; ability to pay; ability to bear, deflect, or otherwise compensate for additional costs, and in particular, the cost of service."[381]

75. The Administrative Law Judge must determine whether Applicant's proposals are just and reasonable when considered together with the PUC's responsibility to ensure consumers can obtain adequate, efficient, and reasonable electric service at rates that fairly compensate the utility for the cost of producing and delivering electricity while giving Applicant the opportunity to earn a reasonable profit.[382]

76. Applicant bears the burden of proving by a preponderance of the evidence that its proposals are just and reasonable.[383]

77. Any doubt about reasonableness should be resolved in favor of the consumer.[384]

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[379] *In re Application of Minn. Energy Res. Corp. for Auth. to Increase Rates for Natural Gas Serv. in Minn.,*, MPUC Docket No. G-011/GR-15-736, Findings of Fact, Conclusions, and Recommendation at 20 (Aug. 19, 2016).
[380] *St. Paul Area Chamber of Commerce v. Minnesota Pub. Serv. Comm'n,* 251 N.W.2d 350, 358 (Minn. 1977).
[381] *In re Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E-002/GR-10-971, Findings of Fact, Conclusions, and Order at 14 (May 14, 2012); *See also* Minn. Stat. §§ 216B.03, .05, and .16 (2016).
[382] Minn. Stat. § 216B.16; *In re Pet. of N. States Power Co. for Auth. to Change its Schedule of Rates for Elec. Serv. in Minn.*, 416 N.W.2d 719, 722-723 (Minn. 1987); *In re Pet. of Minn. Power & Light Company, d.b.a. Minnesota Power, for Auth. to Change its Schedule of Rates for Elec. Utility Serv. in Minn.*, 435 N.W.2d 550, 554 (Minn. App. 1989).
[383] Minn. Stat. § 216B.16, subd. 4.
[384] Minn. Stat. § 216B.03.

A. Class Cost of Service Study (CCOSS)

i. Fixed Production Cost Classification

78. Applicant has utilized classification of fixed production costs as demand-related for several rate cases with PUC approval because the classification is consistent with NARUC guidelines and principles of basing cost classifications on cost causation.[385]

79. The Administrative Law Judge finds Applicant's proposal is just and reasonable.

ii. CCOSS Model and Allocation Methods

80. Applicant has utilized the P&A allocation method in its last two rate cases.[386] The P&A allocation method works with systems like Applicant's that are designed to provide large amounts of energy to a small group of customers along with providing sufficient capacity to meet peak loads for the entire system.

81. The Administrative Law Judge concludes Applicant's use of the P&A allocation method just and reasonable.

iii. Functionalization of 46kV Lines

82. Because the PUC approved Applicant's classification of its 46 kV system as distribution, Applicant has demonstrated by a preponderance of the evidence that the classification is just and reasonable.

iv. Classification of Distribution System

a. Meters

83. The Administrative Law Judge concludes that the cost of the AMI meters is more than merely a customer cost. However, the evidence is not clear on the proportion of the costs to be allocated.

84. Based on the evidence in the record, it appears the customer cost is more than one-third, but clearly not 100 percent.

85. The Administrative Law Judge concludes that the cost of meters should be excluded from the customer costs.

b. Other Distribution Assets

86. The Administrative Law Judge finds that Applicant's classification and allocation of other distribution assets is just and reasonable.

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[385] Ex. 81 at 3-4 (Shimmin Rebuttal).
[386] *Id.* at 6.

B. Revenue Apportionment

87. In 2015, the state implemented a policy to improve the economic prosperity of Applicant's region through the EITE credit, which gives Applicant the opportunity to subsidize certain large power customers financed by surcharges imposed on other customers.[387]

88. The Administrative Law Judge concludes Applicant's proposed revenue apportionment is not just and reasonable. The Administrative Law Judge concludes that EITE customers should receive the smallest increase in rates, if any, and the rates of all other customers should be increased equally proportionate to the cost of service for each class. In other words, the customer classes with the largest percentage revenue deficiency will see the largest increase. However, the apportioned rates should increase no more than 10 percent in order to prevent rate shock.

C. Residential Service Charge

89. Applicant failed to support its claimed residential customer costs. As a result, the Administrative Law Judge concludes that increasing the $8.00 residential service charge to $9.00 is not just and reasonable.

D. Block Rate Design

90. Applicant's current five-block structure appears to be reducing residential electricity consumption. This is the result the PUC intended when it approved it in 2009 and is consistent with the policy of the legislature.[388]

91. The Administrative Law Judge concludes that Applicant's proposal to eliminate the five-block rate structure and implement a new two-block rate structure is not just and reasonable.

E. CARE Program

92. Because Applicant proposes no substantive changes to the CARE program and only seeks to make changes in language to communicate more effectively with customers, Applicant has met its burden of demonstrating that the changes are just and reasonable.

F. Large Power Interruptible Product

93. Because Applicant has not proposed a change in its Large Power Interruptible Product, there is no basis for the Administrative Law Judge to address the issue.

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[387] Minn. Stat. § 216B.1696 (2016).
[388] Minn. Stat. § 216B.03.

G. Large Power Incremental Production Rider

94. Applicant's proposal must be considered together with the PUC's responsibility to ensure consumers can obtain adequate, efficient, and reasonable electric service at rates that fairly compensate the utility for the cost of producing and delivering the electricity, as well as a reasonable profit.[389]

95. Applicant's proposal is aligned with the state policy of aiding the competitiveness of energy intensive trade-exposed industries, such as taconite mining and production.[390]

96. The Administrative Law Judge concludes that Applicant's proposal is just and reasonable.

H. Large Light and Power Time-of-Use Rider

97. Applicant's proposal is reasonably designed to incentivize use of the TOU tariff, which no customer is currently using.

98. The Administrative Law Judge concludes that Applicant's proposal is just and reasonable.

I. Back-up Generation Rider

99. The PUC has already considered and approved the Back-Up Generation program. What remains to be determined is whether Applicant's proposal to pay for it is just and reasonable.

100. The program benefits all customers by ensuring reliability and helping to eliminate the need for a more expensive solution, such as a new large generation plant.

101. The Administrative Law Judge concludes that Applicant's changes to the program are just and reasonable.

J. Green Pricing Program

102. According to Minn. Stat. § 216B.169, subd. 2(b) (2016), when a utility offers customers an option to purchase renewable energy, the rates charged

> must be calculated using the utility's cost of acquiring the energy for the customer and must:

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[389] *In re Pet. of N. States Power Co. for Authority to Change its Schedule of Rates for Electric Service in Minnesota*, 416 N.W.2d 719, 722-723 (Minn. 1987); *In the Matter of the Petition of Minnesota Power & Light Company, d.b.a. Minnesota Power, for Authority to Change its Schedule of Rates for Electric Utility Service Within the State of Minnesota*, 435 N.W.2d 550, 554 (Minn. App. 1989).

[390] Minn. Stat. § 216B.1696 (2016).

(1) reflect the difference between the cost of generating or purchasing the additional renewable energy and the cost that would otherwise be attributed to the customer for the same amount of energy based on the utility's mix of renewable and nonrenewable energy sources[.]

103. Applicant's proposed program would require customers to pay for both renewable energy sources and the fuel required for traditional generation plants. This is inconsistent with Minn. Stat. § 216B.169. The Administrative Law Judge finds it is not just and reasonable for Applicant to require customers to pay for sources of energy that they are not using.

104. However, Applicant's proposed Green Pricing Program should be approved because it aligns with state policy on promoting the use of renewable energy sources. Participating customers should only be charged for a pro-rata share of the energy obtained from traditional sources.

K. Reconnect Pilot

105. The Administrative Law Judge finds the pilot program is just and reasonable.

L. GRID Pilot

106. The Administrative Law Judge finds the pilot program is just and reasonable if some changes are made to the proposal by Applicant. The proposal should be amended to require Applicant to match every dollar raised by the rider.

107. Further, the Administrative Law Judge concludes that the stakeholder advisory committee should be more defined and include a precise number of representatives from specifically identified groups or organizations, not to exceed 12 to 15 people representing an equal number of groups or organizations. This will ensure the group is not too large to function effectively but has wide representation from the community.

M. Credit Card Fees

108. The Administrative Law Judge concludes that Applicant's proposal to no longer charge customers a fee for using a debit or credit card to make payments on their electric bills is just and reasonable.

109. The Administrative Law Judge also concludes that rather than merely shifting the current transaction cost of debit and credit card use to all customers, Applicant should be encouraged to find a more efficient and cost-effective means for processing such payments. This can be accomplished by permitting recovery of only $175,000 for the cost of such transactions, as recommended at Conclusion of Law No. 17.

N. Annual Rate Review Mechanism (ARRM)

110. The ARRM shifts business risk from the utility and its shareholders to customers and is not consistent with any current state policy.

111. Applicant has not shown that its proposed ARRM is just and reasonable.

IV. EFFECT OF STANDARD TARIFFS, ELECTRIC SERVICE AGREEMENTS, AND THE EITE CREDIT ON EXPECTED REVENUE FROM INDUSTRIAL CUSTOMERS

A. U.S. Steel ESA

112. On December 29, 2016, the PUC referred an issue from the approved U.S. Steel ESA to this Docket for a determination of whether the proposed credit is in the public interest.[391]

113. The Administrative Law Judge concludes that the proposed credit in the U.S. Steel ESA is in the public interest and should be approved by the PUC.

B. EITE Credit

114. Under Minn. Stat. § 216B.1696, if an EITE rate is approved, the PUC must allow revenue reductions (or increases) to be passed on to the utility's remaining non-EITE retail customers, with the exception of low-income customers who participate in the Low Income Home Energy Assistance Program.[392]

115. In April 2017, the PUC entered an order in Docket 16-654 requiring that net revenues received from "EITE-customers" be earmarked and refunded to the customers whose rates had funded the program's subsidies to trade-exposed businesses. The EITE Order states in relevant part:

> Minnesota Power shall refund revenue increases associated with the EITE rate schedule as proposed by the Office of the Attorney General on page 13 of its January 31, 2017 Comments in this docket, with the following additions/clarifications:
>
> a. The Company shall use the actual 2016 calendar-year EITE-customer revenue as the baseline for calculating the extent of any refundable increases;

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[391] *In re Pet. by Minn. Power for Approval of an Amended and Restated Elec. Serv. Agreement between United States Steel Corp. and Minn. Power*, MPUC Docket No. E015/M-16-836, Order Approving in part Proposed Electric Service Agreement, Referring Matter to Rate Case, and Closing Docket (Dec. 29, 2016).

[392] Minn. Stat. § 216B.1696, subd. 2(d) (2016).

> b. The Company shall base the refund on net income increases [of 2017 and each subsequent year's EITE-customer revenue over 2016 EITE-customer revenue]….[393]

116. By order issued October 13, 2017 in this proceeding, the PUC approved Applicant's proposal to exclude rider revenue from its 2016 baseline calculation.[394] Additionally, the PUC directed Applicant to use the actual 2016 calendar-year EITE-customer revenue as the baseline for calculating the extent of any refund.[395] As the PUC reasoned, failing to do so "would essentially deprive EITE customers of the full benefit of the EITE rate as intended by the statute."[396]

117. As a result of Applicant's increased electricity sales to EITE customers and the PUC's October 13, 2017 Order, the EITE subsidy incurred by non-EITE customers appears to be non-existent at the current time. Thus, rates should be determined without consideration of the EITE credits. However, rate design should be pursued to meet the intent of the legislature as described under Minn. Stat. § 216B.1696.

118. Any conclusions of law more properly designated as findings of fact are hereby adopted as such.

Based upon the conclusions of law, and for the reasons explained in the accompanying memorandum, which is hereby incorporated by reference, the Administrative Law Judge makes the following:

RECOMMENDATION

1. The test year revenue increase sought by Applicant is not reasonable and will result in excessive earnings. The test year revenue should be recalculated by Applicant based on the findings, conclusions, and reasons described in this report.

2. The test year revenue increase sought by Applicant is not just and reasonable and will result in excessive earnings. Recalculations should be made by Applicant based on the findings, conclusions, and recommendations in this report.

3. Applicant's proposed capital structure and return on equity may not be reasonable and should be recalculated based on the Department's proxy list and using the two variants of the DFC model.

4. The overall rate design proposed by Applicant is not just and reasonable. The current design should remain in place, with the changes recommended by this report incorporated.

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[393] *In re Pet. to Ensure Competitive Electric Rates for Energy-Intensive Trade-Exposed Customers*, MPUC E015/M-15-564, Order Authorizing Cost Recovery with Conditions at 12 (Apr. 20, 2017).
[394] Order Excluding Rider Revenue at 8 (Oct. 13, 2017) (eDocket No. 201710-136464-01).
[395] *Id.*
[396] *Id.* at 5, 8.

5. Expected revenue from industrial customers will not likely be changed from standard tariffs, ESAs, and the EITE credit. The rate design should be modified consistent with the recommendations in this report in order to meet the spirit of Minn. Stat. § 216B.1696.

Dated: November 7, 2017

JIM MORETNSON
Administrative Law Judge

NOTICE

Notice is hereby given that exceptions to this Report, if any, by any party adversely affected must be filed under the timeframes established in the Commission's rules of practice and procedure, Minn. R. 7829.2700, .3100 (2017), unless otherwise directed by the Commission. Exceptions should be specific and stated and numbered separately. Oral argument before a majority of the Commission will be permitted pursuant to Minn. R. 7829.2700, subp. 3. The Commission will make the final determination of the matter after the expiration of the period for filing exceptions, or after oral argument, if an oral argument is held.

The Commission may, at its own discretion, accept, modify, or reject the Administrative Law Judge's recommendations. The recommendations of the Administrative Law Judge have no legal effect unless expressly adopted by the Commission as its final order.

MEMORANDUM

I. SUMMARY OF THE APPLICATION

On November 2, 2016, Minnesota Power (Applicant) filed a five volume application with the Public Utilities Commission (PUC or Commission) for authority to increase general electric rates to its retail customers by $55,123.680, or 9.1 percent, effective January 1, 2017.[397] Applicant requested that if the PUC suspended the proposed rate increase that an interim rate increase of $48,632,259, or 8 percent, be effective January 1, 2017.[398] Applicant also advised the PUC that it wanted to change its rate design and terms of service.[399]

Applicant's purpose in proposing the rate increase is to produce additional revenue it believes is necessary to meet the cost of service for the test year ending December 31, 2017.[400]

On December 12, 2016, Applicant advised the PUC that it was seeking a lower interim rate increase of $34,732,113, or 5.6 percent.[401] This request was due to increases in production expected to be experienced by some of Applicant's industrial customers.[402] Applicant advised the PUC that the volatility of its industrial customers' businesses led it to propose an Annual Rate Review Mechanism (ARRM) to protect both Applicant and its customers from uncertainty over future customer loads on its electricity system.[403]

During the course of these proceedings Applicant made adjustments to its revenue request. On February 28, 2017, due to changes in the sales forecast, Applicant reduced its requested average rate increase to $38.8 million, or a 6.1 percent increase from current rates.[404] On July 21, 2017, due to further revisions to revenues and expenses, Applicant revised its requested average rate increase to $49.2 million, or an 8 percent increase from current rates.[405]

II. REASONABLENESS OF TEST YEAR REVENUE INCREASE

A. Legal Standards

The PUC may suspend a public utility's rate increase and refer the matter to the OAH for a contested case hearing if the PUC, on its own, and with the then-existing record, cannot determine the reasonableness of the rates requested.[406]

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[397] Summary of Filing (Nov. 2, 2016) (eDocket No. 201611-126215-02).
[398] *Id.*
[399] *Id.*
[400] Notice of Change in Rates at 2-3 (Nov. 2, 2016) (eDocket No. 201611-126215-02).
[401] Letter from Moeller to Wolf (Dec. 12, 2016) (eDocket No. 201612-127211-01).
[402] *Id.* at 1-2.
[403] *Id.* at 3.
[404] Ex. 84 at 2-3, MAP-SD-1 (Podratz Suppemental Direct).
[405] Ex. 87 at 21, MAP-S-2 (Podratz Surrebuttal).
[406] Minn. Stat. § 216B.16, subd. 2(b).

The rates must "be just and reasonable."[407] They must "not be unreasonably preferential, unreasonably prejudicial, or discriminatory."[408] Rates must "be sufficient, equitable, and consistent in application to a class of consumers."[409] In short, rates must balance the needs of the utility and the ratepayers. The Minnesota Legislature set forth general factors for the PUC, and thus the Administrative Law Judge, to consider when determining just and reasonable rates. For the ratepayers, "due consideration to the public need for adequate, efficient, and reasonable service" must be made.[410] The utility's need "for revenue sufficient to enable it to meet the cost of furnishing the service, including adequate provision for depreciation" of property used in rendering the service must be considered.[411] Additionally, the utility is entitled to "earn a fair and reasonable return upon the investment in such property."[412]

Setting reasonable rates begins with determining the rate base over which the utility is entitled to obtain a fair rate of return. To make this determination, the PUC, and thus the Administrative Law Judge, must:

> give due consideration to evidence of the cost of the property when first devoted to public use, to prudent acquisition cost to the public utility less appropriate depreciation on each, to construction work in progress, to offsets in the nature of capital provided by sources other than the investors, and to other expenses of a capital nature.[413]

When determining rate base, no allowance is to be made for the current estimated replacement value of the utility's property.[414] As the United States' Supreme Court has explained:

> What annual rate will constitute just compensation depends upon many circumstances, and must be determined by the exercise of fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; . . . The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical

[407] Minn. Stat. § 216B.03.
[408] *Id.*; *see also* Minn. Stat. § 216B.16, subd. 5.
[409] Minn. Stat. § 216B.03
[410] Minn. Stat. § 216B.16, subd. 6 (2016).
[411] *Id.*
[412] *Id.*
[413] *Id.*
[414] *Id.*

> management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties.[415]

Finally, the utility carries the burden of proof to show the rate change is just and reasonable.[416] The standard of proof is a preponderance of the evidence.[417] The establishment of a claimed cost is evaluated by the tribunal in its quasi-judicial capacity in terms of whether it is more likely than not that the utility incurred the cost. But the PUC also has a quasi-legislative capacity, and in ratemaking proceedings the tribunal must consider "whether the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility considered together with the Commission's statutory responsibility to enforce the state's public policy that retail customers of utility services shall be furnished such services at reasonable rates."[418] This means that a utility must provide a preponderance of the evidence that the facts are accurate, the costs they seek to recover are rate-recoverable, that the recovery mechanisms they propose are permissible, and that the rate design they advocate is equitable.[419] Minnesota courts have clarified that in the evaluation of "disputes in the typical rate case, the accent is more on the inferences and conclusions to be drawn from the basic facts (i.e., amount of claimed costs) rather than on the reliability of the facts themselves."[420] To determine whether such cost is just and reasonable requires a determination about "whether the ratepayers or shareholders should bear those costs."[421] "Any doubt as to reasonableness should be resolved in favor of the consumer."[422]

B. Positions of Parties

i. Applicant

Applicant asserts its average rate base for the 2017 test year is $2,092,387,441.[423] The claimed rate of return is 7.548 percent, a decrease from 7.6 percent.[424] Applicant's claimed required operating income is $157,933,404, a $35,912 decrease from its initial filing.[425] Applicant argues its actual operating income is $141,700,385, an increase of $16,050,083 from its initial filing.[426] Therefore, the income deficiency is $16,233,019, according to Applcant.[427]

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[415] *Bluefield Waterworks & Imp. Co. v. Public Service Commission*, 262 U.S. 679, 694 (1923).
[416] Minn. Stat. § 216B.16, subd. 4.
[417] *In re Minn. Power & Light Co.*, 435 N.W.2d 550, 554 (Minn. Ct. App. 1989).
[418] *Id.* (quoting *In re Petition of N. States Power Co.*, 416 N.W.2d 719, 722 (Minn. 1987)).
[419] *In re Application by CenterPoint Energy Res. Corp. d/b/a CenterPoint Energy Minn. Gas for Auth. to Increase Nat'l Gas Rates in Minn.*, MPUC Docket No. G008/GR-13-316, Findings of Fact, Conclusions of Law, and Order at 4 (June 9, 2014).
[420] *In re Minn. Power & Light Co.*, 435 N.W.2d 550, 554 (Minn. Ct. App. 1989) (quoting *In re Petition of N. States Power Co.*, 416 N.W.2d 719, 722-23 (Minn. 1987)).
[421] *Petition of Northern States Power Co.*, 416 N.W.2d 719, 722-23 (Minn. 1987).
[422] Minn. Stat. § 216B.03.
[423] Ex. 86 at 6, 16, MAP-R-7 (Podratz Rebuttal).
[424] *Id.*
[425] *Id.*
[426] *Id.*
[427] *Id.*

Applicant seeks to apply a gross revenue conversion factor of 1.705611.[428] This results in a gross revenue deficiency of $27,687,216.[429] This is a $27,436,464 decrease from Applicant's initial filing.

The Applicant made many changes to its original and revised requests for a rate increase. These changes followed from updated data and suggestions from other parties. The following is a list of such changes:

- Straight River 115 kV transmission line project actual costs were $371,882 less than budgeted and noted in the original filing.[430] This results in a reduction of $242,903 to the rate base.[431] Additionally, adjustments to depreciation expense and property tax should be made in the respective amounts of $8,025 and $10,059.[432]

- The depreciation life of the Hibbard Renewable Energy Center (HREC) in Duluth should be extended to 2029.[433] This results in a reduction of $846,393 to a depreciation reserve and an increase of $350,153 to accumulated deferred income taxes.[434] The resulting adjustment of the depreciation expense should be $1,692,786.[435]

- 2017 production tax credits (PTCs) for wind energy were changed by the Internal Revenue Service (IRS) in April 2017.[436] The PTC rate was increased from $23 per megawatt hour (MWh) to $24 per MWh.[437] Thus, adjusting the PTCs based on the new rate results in a PTC of $41.830 million (Total Company) as opposed to $40.087 million.[438] This change effects the deferred tax expense, lowering it to $1,462,487.[439]

- An additional change to the accumulated deferred income taxes results from the adjustment to the 2017 PTCs. Accumulated deferred income taxes are reduced by $731,243, which increases the rate base by the same amount.[440]

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[428] *Id.*
[429] *Id.*
[430] *Id.* at 4.
[431] *Id.*
[432] *Id.* at 11.
[433] *Id.* at 4.
[434] *Id.* at 5.
[435] *Id.* at 11.
[436] Ex. 55 at 4 (Jago Rebuttal).
[437] *Id.*
[438] *Id.* at 3, 5, 14.
[439] *Id.* at 5.
[440] Ex. 86 at 5 (Podratz Rebuttal).

- Cash working capital was adjusted and is now negative $26,990,577.[441]

- Deferred storm cost for 2016 storm damage and amortization of the Sappi/Cloquet Turbine/Generator 5 were operating income adjustments for the test year.[442] The deferred storm damage amount was $732,272 and the Sappi/Cloquet Turbine/Generator 5 amortization was $232,618.[443]

- Applicant is seeking an additional $1,613,728 for test year storm response costs.[444]

- Applicant adjusts third-party transmission revenue to $1.836 million.[445]

- Applicant removed $21,584 from cost for customer information software.[446]

- Applicant recommends reducing test year employee compensation costs by $2,969,621.[447]

- Applicant will reduce test year spot bonus gift card expenses by $14,380.[448]

- Applicant will update its pension expense for the 2017 test year. This adjustment results in a $519,375 reduction.[449]

- Applicant states it should have excluded $14,630 (Total Company) for dues paid to organizations engaged in lobbying.[450] This is in addition to $149,195 previously excluded for lobbying-related activity.[451]

- Applicant reduced its 2017 test year employee expenses another $857.50 for employee travel expenses that should be excluded.[452]

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[441] *Id.*, MAP-R-3 at 1.
[442] *Id.* at 7.
[443] *Id.* at 8.
[444] *Id.*; Ex. 50 at 11 (Fleege Rebuttal).
[445] Ex. 85 at 10 (Podratz Supplemental Direct).
[446] *Id.* at 11-12.
[447] *Id.* at 12.
[448] *Id.*
[449] *Id.*
[450] Ex. 55 at 18 (Morris Rebuttal).
[451] *Id.*
[452] *Id.* at 12.

- The conservation expense is reduced by $125,000 to align with a 2016 PUC approved expense of $10,447,625.[453]

- State income tax should be reduced by $29,419 and federal income tax should be reduced by $94,770 to reflect interest synchronization.[454]

Intervenors raise numerous issues with Applicant's accounting of its rate base. These issues result in sub-issues to be considered and resolved in order to arrive at a finding of Applicant's average rate base for the 2017 test year. These sub-issues are addressed in the Analysis sections below.

ii. LPI

LPI argues Applicant is entitled to a rate of return of 6.96 percent.[455] LPI claims Applicant's revenue deficiency is negative $2.2 million, as opposed to $27.7 million.[456] LPI claims the following reductions should be made to the $27.7 million claimed deficiency:

- Reduction of $16.3 million based on a return on equity of 9.3 percent.

- Reduction of $6.7 million based on a common equity ratio of 51 percent.

- Reduction of $800,000 in cash working capital.

- Reduction of $1.7 million in sales revenues.

- Reduction of $2.3 million in incentive compensation.

- Reduction of $1.4 million in executive benefits.

- Reduction of $700,000 in storm restoration expenses.[457]

iii. ECC

ECC argues that the test year revenue increase is not reasonable. ECC's argument is based on the Department position that Applicant currently has a revenue surplus of $16,754.079. In addition, ECC relies on an OAG position that Applicant anticipates further increases in sales to large power customers because the EITE credit is designed to incentivize production increases.

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[453] Ex. 85 at 13-14 (Podratz Supplemental Direct – Trade Secret).
[454] *Id.* at 16.
[455] Ex. 103 at 2, CCW-1(Walters Direct).
[456] Ex. 111 at 2-3 (Rackers Surrebuttal).
[457] *Id.* at 3.

iv. CEO

As noted above, CEO believes the test year revenue increase sought by Applicant is not reasonable. CEO argues that permitting Applicant to extend the depreciation date of the entire BEC to 2050 will incentivize Applicant to keep the plant operating beyond its economically useful life or for other reasons. CEO argues that while Applicant's proposal will reduce revenues in the near term, due to lower depreciation expenses it will increase overall earnings from the asset; especially if BEC remains operational for a longer period. CEO suggests an alternative means to ensure Applicant can recover the costs of BEC while transitioning to cleaner energy sources. This would involve the use of a ratepayer-backed bond which would mitigate the rate impact of the early retirement in BEC 1 and 2, as well as any possible early retirement of BEC 3 and BEC 4.[458]

v. WAL-MART

WAL-MART argues the test year revenue request is unreasonable. WAL-MART believes the return on equity used for the test year, 10.15 percent, is too high.

vi. MCC

MCC takes no position on whether the test year revenue is reasonable.

vii. FDL

FDL takes no position on whether the test year revenue is reasonable, but argues that any increase that would result in higher rates without corresponding improvements in reliability of service is unreasonable.

viii. CUB

CUB takes no position on whether the test year revenue is reasonable. CUB objects to the GRID modernization proposal, which is addressed under the rate design issue.

ix. AARP

AARP takes no position on whether the test year revenue is reasonable, but opposes any increase that would result in unreasonably high rates for the residential customer class or that would result in unreasonable and excessive earnings to Applicant.

x. OAG

OAG believes the test year revenue sought by Applicant is not reasonable. OAG raises 13 sub-issues to demonstrate its position. These include:

- Transmission Capital Additions

[458] Ex. 255 at 5-11 (Varadarajan Rebuttal).

- Generation Capital Additions
- Depreciation for the BEC
- Costs Related to Early Retirement of BEC 1 and 2
- Storm Damage Amortization Expense
- Sappi/Cloquet Generator Amortization Expense
- Credit Card Processing Fees
- Charitable Contributions
- Membership Dues
- Employee Gifts
- Travel, Entertainment, and Employee Expenses
- Sales Forcasts
- Adjustable Rate Review Mechanism (ARRM)

xi. Department

The Department believes Applicant has not demonstrated the reasonableness of its proposed rate increase. In fact, the Department believes Applicant has a revenue surplus of $16,754,079, which should result in an overall rate decrease of that amount, based on revenue of $622,064,602. According to the Department, Applicant's test year rate base and operating income does not provide a reliable basis for setting rates and so the test year revenue increase sought is unreasonable unless specific adjustments are included. The Department seeks adjustments in the following areas:

- Storm Damage Amortization Expense
- Sappi/Cloquet Generator Amortization Expense
- Transmission Revenues and Expenses
- 2016 Transmission Capital Projects
- 2017 Transmission Capital Projects
- Hibbard Renewable Energy Center (HREC) Deprecitation Life
- Depreciation for BEC 1 and 2
- Prorated Accumulated Deferred Income Taxes (ADIT)
- Production Tax Credit (PDT) True-Up and Investment Tax Credit (ITC)
- Other Employee Benefits
- Pension Expenses and Prepaid Pension Asset
- Base Rider Cash Collections
- Test Year Cash Working Capital
- Executive Deferral Account (EDA) Expense
- Executive Investment Plan (EIP) Expense
- Other Incentives – High Performance Awards Expense, Spot Bonus Expense, and Interest on Benefits and Other Awards
- Test Year Compensation Expense-Unfilled Positions
- State and Federal Income Tax
- Credit Card Payment Fees
- Administrative Cost of MP Foundation

- Using Three-year Average For Employee Expenses
- Additional Costs/Revenues in the Fuel Clause
- Current Energy Recovery Mechanism
- Base Cost of Energy
- Class Cost Factors in Fuel Clause Adjustment (FCA)
- Fuel Clause Transition Cost Recovery
- Forecasted FCA Mechanism
- Generation O&M Supervision & Engineering Expenses and Meter Reading Expenses
- Economic Development Expenses
- Conservation Improvement Program (CIP) Expenses
- Sales Forecast

C. Analysis of Sub-Issues in Dispute

i. Boswell Energy Center Life Extension

Positions of Parties

BEC, with all four generators, is Minnesota Power's largest thermal generation facility, all fueled by coal and a combined total capacity of over 1,000 MW.[459] Since 2007, substantial investments have been made at BEC, including an environmental retrofit of BEC3 that was completed as of the Company's last rate case and an environmental retrofit of BEC4 that was recently completed in 2016.[460] In 2015, the PUC approved the current remaining lives for the BEC facilities.[461] In October 2016, the Company announced that it is closing BEC1&2 at the end of 2018 with respect to the production of energy from those units.[462] However, the BEC Units and Common Facilities are not stand-alone facilities: they share unit-critical electrical, water, and heating infrastructure, ancillary services, and fuel handling.[463] BEC1&2 provide support to BEC3 and BEC4 during black-start procedures, ongoing operations, and during critical system restoration activities.[464]

Minnesota Power's request to consolidate and extended the depreciation life to 2050 is intended to address several important considerations:

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[459] Ex. 40 at 16 (Minke Direct).
[460] *Id.* at 16.
[461] *See In re Minn. Power's 2015 Remaining Life Depreciation Petition*, MPUC Docket No. E015/D-15-711, Petition at 10 (July 31, 2015) (proposing remaining lives), Briefing Papers at 2 (Aug. 10, 2016) (explaining that the only disputed issues pertained to facilities other than BEC).
[462] Ex. 40 at 17 (Minke Direct).
[463] *Id.*; Ex. 46 at 16-17 (Skelton Rebuttal).
[464] Ex. 40 at 19 (Minke Direct).

- It is a rate mitigation option that will reduce the annual costs of BEC for customers.465 Specifically, it will reduce the revenue requirement in this rate case by $22.7 million.466
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- It will provide greater cost certainty for customers, even as the future operational lives of BEC3 and BEC4 are likely to be affected by potential future environmental and regulatory requirements.467
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- It will provide greater financial certainty for the Company, which likewise supports better financial planning and facilitates response to future environmental regulations.468
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- It will provide operational certainty for the Company: establishing accounting for the 2018 closure of BEC1&2 allows for workforce transition, engineering, and permitting planning for the closure of those units.469
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- It reflects the Company's effort to thoughtfully and equitably balance the impact on current customers as compared to the impact on future customers in light of the current rapid transition in how energy is generated.470

According to Applicant, the request to extend the consolidated BEC remaining life to 2050 was driven, in substantial part, by the BEC4 retrofit, which (when combined with the BEC3 retrofit completed in 2009), justifies an extended life for the length of time the equipment may operate.[471] To support this potential extended operational life, Minnesota Power obtained an opinion from the engineering firm Burns & McDonnell.[472] This opinion concluded that "we see no technical reasons that Boswell Energy Center could not physically be operated until 2050, with appropriate maintenance and investments into replacements and upgrades."[473] Further, the mandated retrofits at BEC3 and BEC4 required substantial financial investment; by extending the depreciation schedule, the Company mitigates the impact of these investments on customers.

Applicant argues its request is consistent with applicable Minnesota law. The Commission is directed to "fix proper and adequate rates and methods of depreciation, amortization, or depletion in respect of utility property."[474] Minnesota Power is required to follow the Federal Energy Regulatory Commission (FERC) uniform system of accounts,

[465] *Id.* at 15, 20.
[466] *Id.*at 15, HGM-8.
[467] *Id.* at 16-17, 19-20.
[468] *Id.* at 19-20.
[469] Ex. 42 at 10 (Minke Rebuttal).
[470] *Id.* at 13-14.
[471] Ex. 40 at 18 (Minke Direct).
[472] *Id.,* HGM-10.
[473] *Id.*
[474] Minn. Stat. § 216B.11 (2016).

and related orders and regulations (FERC accounting).[475] In general, FERC accounting depreciates the remaining balance of an asset over the estimated service life of the asset. But in establishing the service lives of utility assets for depreciation certification studies, the Commission requires straight-line depreciation (which the Company proposes) even while "[n]o specific methods are prescribed by the Commission in estimating service lives and salvage value."[476] Consistent with this principle, "[j]ust as the Commission's resource planning order to close Units 1 and 2 by 2022 did not result in a specific directive to change the depreciation life of those units, [the Company's] proposal does not change the potential operating lives of any of the Boswell units."[477]

Applicant also argues that the PUC will eventually order it to stop using BEC 1 and 2 due to environmental impacts. Applicant argues that its request can be considered a proactive request for Minn. Stat. Minn. Stat. § 216B.16, subd. 6 to be applied in anticipation for this eventuality.[478]

CEO, OAG, and the Department all object, to various degrees, to Applicant's proposal to consolidate the four service units at BEC and lengthen the combined depreciation period to 2050. LPI and MCC agree with Applicant's proposal.[479]

CEO objects because they believe the proposal will provide short-term savings for current ratepayers at the expense of future ratepayers who will receive no benefit from the generating facility.[480] Further, according to CEO, Applicant's proposal will incentivize it to later continue use of its coal burning facilities rather than shift to clean energy. CEO offers suggestions for Applicant and the PUC to meet the economic goals of Applicant while not creating the potential adverse effect of extending the life of the coal burning facility.

OAG argues that there is insufficient information to consolidate the four units at BEC at this time.[481] OAG argues that BEC 3 and BEC 4 should not have their remaining lives extended beyond the current approved lifespan of 2034 and 2035, respectively.[482] OAG states that the impact of its position is an increase of the depreciation expense of $16,488,412, and a reduction in rate base returns of $555,378, for a net increase of $15,933,034.[483]

The Department argues that the depreciation life for BEC 1 and 2 should be set to end in 2022, consistent with the PUC order to retire BEC 1 and 2 when sufficient energy

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[475] Minn. R. 7825.0300, subp. 2 (2017).
[476] Minn. R. 7825.0800 (2017).
[477] Evidentiary Hearing Tr. Vol. 1 at 74 (Minke).
[478] Applicant Initial Br. at 12 (Sept. 12, 2017) (eDocket No. 20179-135459-02).
[479] Ex. 108 at 3 (Rackers Rebuttal); Ex. 301 at 7 (Blazar Rebuttal).
[480] Ex. 254 at 4, 6-8 (Varadarajan Direct); Ex. 255 at 5, 12-14 (Varadarajan Rebuttal); Ex. 256 at 3 (Varadarajan Surrebuttal).
[481] Ex. 505 at 6-30 (Lee Direct).
[482] *Id.* at 31-35.
[483] *Id.* at 30.

and capacity are available, and no later than 2022.[484] According to the Department, this would result in a revenue requirement increase of $5,053,194.[485] Alternatively, in light of the announcement that Applicant will retire BEC 1 and 2 in 2018, the Department argues the remaining life could be set for the same time.[486] This, according to the Department, would result in a $17,278,665 increase in revenue requirements.[487] The Department agrees that BEC 3, BEC 4, and the common facilities could operate until 2050, due to significant capital upgrades which included addressing environmental requirements.[488]

Analysis

Depreciation refers to the loss of an asset's service value which is:

> not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities[.][489]

Depreciation accounting is "a system of accounting which aims to distribute cost or other basic value" of, for example, a utility plant, less salvage, "over the estimated useful life of the unit, which may be a group of assets, in a systematic and rational manner."[490]

A utility's rates must be set with the goal of providing the utility a reasonable opportunity to recover its costs plus a fair return on its assets.[491] The cost of depreciation impacts the value of assets upon which the utility earns a return. The longer the period for depreciation, the longer the utility can earn a return on an asset, and the smaller the cost will be, annually, that is passed on to ratepayers.

Applicant's proposal regarding the BEC is two parts. First, Applicant wants to consolidate the four components of the facility into one for accounting purposes. Second, Applicant wants that single facility's useful life to be extended to 2050 for purposes of depreciation. Generally, the straight-line method for calculating depreciation in employed.[492] The straight-line method uses the original cost of an asset adjusted nor net salvage, which is typically charged to operating expenses, and is "credited to the accumulated provision for depreciation through equal annual charges over its probable

[484] Ex. 629 at 42, 44 (Campbell Direct); *In re Minn. Power's 2016-2030 Integrated Resource* Plan, MPUC Docket No. E-015/RP-15-690, Order Approving Resource Plan With Modifications at 15 (July 18, 2016).
[485] Ex. 629 at 44 (Campbell Direct).
[486] *Id.*
[487] *Id.* at 44-45.
[488] *Id.* at 42.
[489] Minn. R. 7825.0500, subp. 6 (2017).
[490] *Id.,* subp. 7.
[491] Minn. Stat. § 216B.16, subd..
[492] Minn. R. 7825.0800.

service life.[493] Probable service life is defined as "that period of time extending from the date of [an asset's] installation to the forecasted date when it will probably be retired from service."[494] Any exception to the straight-line method of depreciation accounting requires "justification and certification by the commission."[495]

Applicant's proposal should be denied because it is inconsistent with prior PUC determinations, including a recent determination that "it would not be reasonable to allow [Applicant] to depreciate an asset it no longer owns."[496] This approach ensures that the risk taken by shareholders in building or using particular generating facilities is not shifted to ratepayers when the utility determines to make a change that the PUC has not specifically required.

The current approved remaining life for BEC 1 and 2 is 2024.[497] However, Applicant intends to retire BEC 1 and 2 in 2018.[498] BEC 3's approved remaining life is 2034, and BEC 4 is 2035.[499] The common facilities remaining life is 2030, the average of the other three. Applicant does not intend to operate BEC 3 and BEC 4 past their current approved remaining life, although it maintains that they could be operated until 2050.[500]

There are no legal standards for the consolidation of assets for accounting purposes. However, a "unit" for accounting purposes may be a group of units, under PUC rules.[501] In any event, depreciation is to be based on "the estimated useful life of the unit… in a systematic and rational manner."[502] Given the varied estimated useful lives of the various units that make up the BEC (2024, 2034, and 2035), there is not a rational basis to group them all together. This issue is more pronounced given that Applicant intends to retire BEC 1 and 2 in 2018. Thus, consolidation of all units at the BEC for accounting purposes is not recommended.

It makes sense to group BEC 3, BEC 4, and the common facilities. BEC 3 and BEC 4 currently have approved remaining lives that are one year apart. Further, there is evidence they could both operate to 2035, BEC 4's remaining life, and beyond. The common facilities life is merely an average based on the inclusion of BEC 1 and 2, and should be aligned only with BEC 3 and BEC 4.

Conclusion

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[493] Minn. R. 7825.0500, subp. 14 (2017).
[494] *Id.*, subp. 10 (2017).
[495] Minn. R. 7825.0800.
[496] *In re Minn. Power's 2015 Remaining Life Depreciation Petition*, MPUC Docket No. E-015/D-15-711, Order Approving Remaining Lives and Salvage Rates As Modified And Required Filings at 7 (Sept. 19, 2016).
[497] Ex. 40 at 17 (Minke Direct).
[498] *Id.*
[499] *Id.*
[500] *Id.* at 15-19; Ex. 42 at 8 (Minke Rebuttal).
[501] Minn. R. 7825.0500, subp. 7.
[502] *Id.*

BEC 1 and 2 should be depreciated until 2022 because of the impact of the PUC's orders on Applicant's decision to retire them early. This should be done despite Applicant's announcement that it will retire BEC 1 and 2 in 2018, because it will reduce the financial impact on both ratepayers and Applicant's shareholders. Such a variance avoids an excessive burden on the Company by permitting some additional recovery on the two units within a more reasonable timeframe than 2018. Further, it raises few, if any, issues with intergenerational equity. The PUC's consideration of intergenerational equity as a lens to view the public interest has been upheld by the Minnesota Supreme Court.[503] The reduced impact on ratepayers by extending the depreciation of BEC 1 and 2 for four years is in the public interest, while not pushing the costs on another generation of ratepayers up to 25 years into the future, long after the units are no longer used and useful. Further, future ratepayers may be harmed by paying for generation assets no longer in existence, or used and useful, while also having to pay for possible new assets. Finally, a variance is more in line with the standards imposed by law than the complete consolidation of the units and extension of depreciation to 2050.

BEC 3, BEC 4, and the common facilities should be depreciated until 2035, the current maximum approved life of any of the three units. As long as 2035 is the maximum approved remaining life, that period is the probable service life of the group of units and would ensure the depreciation calculation is in conformity with the presumptive straight-line method for calculating depreciation. Applicant's proposal shifts shareholder risk to ratepayers. The proposal also shifts the burden of paying for assets from which current ratepayers receive the benefit to future ratepayers who will be paying for assets from which they do not receiving benefit. Any other benefits those future ratepayers may reap because of the early retirement of BEC 1 and 2, or the retirement of BEC 3 and 4 in 2035, will be ancillary, and not appropriately attributed to them. Indeed, those ratepayers may be entitled to the reduced cost of renewable energy, not the cost of their parents' and grandparents' relatively dirty energy.

Applicant should be required to recalculate its test year number based, in part, on these recommendations

ii. Transmission Capital Projects

Positions of the Parties

Applicant seeks to include the capital costs of a number of projects into its rate base. Applicant seeks to incorporate the costs of projects incurred from 2010 to 2015 which were not recovered in its rider, as well as 2016 forecast amounts and 2017 budgeted amounts.[504] Applicant updated the list of projects during the rate case. It removed two projects that were being deferred (5 Line Re-conductor and Hoyt Lakes Ring Bus Reconfigure) that were worth $4.3 million.[505] In place of those two projects, Applicant

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[503] *In re Review of 2005 Annual Automatic Adjustment of Charges For All Electric and Gas Utilities*, 768 N.W.2d 112, 123-24 (Minn. 2009).
[504] *Id.*
[505] Ex. 629, NAC-11 (Campbell Direct).

added five high priority projects that needed to be completed in 2017.[506] These projects, worth $4.6 million, are: 109078 North Shore 115 kV Switch Station; 109253 ETCO Capacitor Bank; 109039 Forbes 3T Breaker & 3TR Panel; 109047 Boswell 95 Line Upgrade and 109052 Blackberry 95 Line Upgrade (treated as one project); and 109176 Minntac 50L and 109177 Minntac 54L (treated as one project).[507]

The Department believes Applicant has developed and handled testimony about transmission projects in a way that limits the ability of parties to review the projects adequately.[508] The Department also takes issue with Applicant revising its testimony and schedules over the course of the rate case with new or revised information.[509] According to the Department, this has limited its ability to carefully review the information provided within the timeframe of the hearing process.[510]

The Department also argues that the changes Applicant made to the information on transmission projects shows it did not meet its burden to demonstrate the requested rate increase is just and reasonable.[511] The Department argues that because Applicant did not provide the percentage of completion amounts for the new projects, it did not provide sufficient information to support their inclusion in the 2017 test year.[512]

The Department also argues that the two deferred projects, the 5-Line Re-conductor project and the Hoyt Lakes Ring Bus Reconfiguration Project, and the five replacement projects be removed from the test year.[513] OAG agrees with this position.[514] Such change would remove $16.4 million from the calculation for the test year base rate, total company, and reduces the test year revenue requirements by $364,875.[515]

Analysis

Applicant provided evidence to support its revised claim to include transmission capital projects in the test year. Several parties objected with motions to exclude the evidence. The objections to the handling of the revisions were not accompanied by any clear evidence of prejudice. More importantly, Applicant did provide, in its response to the Department's request for information, justification for two projects it changed: the 5-Line Re-conductor and Hoyt Lakes Ring Bus Reconfiguration projects. Applicant stated that four new projects must be in service in 2017, each for a specific reason, and that one project was already completed.[516] Thus, it is immaterial whether Applicant advised the

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[506] *Id.*
[507] *Id.*
[508] Ex. 630 at 23 (Campbell Surrebuttal).
[509] *Id.* at 24.
[510] *Id.*
[511] *Id.* at 25.
[512] Ex. 629 at 27 (Campbell Direct).
[513] *Id.* The deferred projects have been removed from the test year by Applicant. *See* Ex. 50 at 21, 24 (Fleege Rebuttal).
[514] Ex. 507 at 38 (Lee Rebuttal).
[515] Ex. 629 at 27-28 (Campbell Direct); Ex. 50 at 19 (Fleege Rebuttal); Ex. 505 at 11 (Lee Direct).
[516] Ex. 629, NAC-11 (Campbell Direct).

Department of the current status of all five projects since it clearly intended all five to be completed in the test year.

The Department and OAG do not provide any legal support for their position that Applicant should not be permitted to re-prioritize its capital projects, including replacing one project with another. The Department argues that the present case is distinguishable from Docket No. E002/GR-13-868 (Xcel Energy).[517] That case was cited by Applicant arguing that a utility is entitled to flexibility in managing capital projects that can change for various reasons.[518] According to the Department, the projects in Xcel Energy were not eligible for rider recovery.[519] The Department argues Applicant has a transmission cost recovery rider (TCR) to recover the cost of its transmission projects and that this fact requires closer scrutiny of any rider-related changes.[520] However, Applicant correctly argues that the PUC recognizes the dynamic nature of managing capital projects.[521] As the PUC has stated, if it "is to consider updated in-service-date information provided during the course of the rate case, it is reasonable also to consider the Company's list of projects that are candidates to substitute for delayed or canceled projects as well."[522] Here, when Applicant replaced two high-dollar capital transmission projects (5 Line Re-conductor and Hoyt Lakes Ring Bus Reconfiguration) with several higher-priority projects; it had the right to do that. The record includes the justification for these projects, and there is no reason to conclude they are not necessary.

Conclusion

Applicant met its burden of demonstrating the value of its final list of claimed capital transmission projects in the test year. No changes to Applicant's final test year calculations should be made based on this sub-issue.

iii. Generation Capital Projects

Positions of the Parties

Since Applicant's initial filing, seven of 68 capital generation projects have been deferred from 2017 and replaced with six projects of higher priority.[523] The original seven projects totaled $1,942,887.[524] The six replacement projects total $1,209,791.[525] Simply removing the original seven projects reduces the revenue requirement for generation capital projects by $107,403.[526] Applicant anticipates that additional projects will arise in 2017, and so the original filing request remains "reasonably representative of our capital

[517] *Id.* at 26.
[518] Ex. 50 at 26 (Fleege Rebuttal).
[519] Ex. 630 at 27 (Campbell Surrebuttal).
[520] *Id.*
[521] *In re Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E-002/GR-13-868, Findings of Fact, Conclusions of Law, and Order at 27 (May 8, 2015).
[522] *Id.*
[523] Ex. 46 at 2-7 (Skelton Rebuttal).
[524] Ex. 507, SL-R-1 at 5 (Lee Rebuttal).
[525] Ex. 46, JJS-1 (Skelton Rebuttal).
[526] Ex. 507, SL-R-1 at 5 (Lee Rebuttal).

investments for 2017."[527] No figures were provided showing the revenue requirement based on the new projects minus the deferred projects.

OAG maintains that the original seven projects should be removed from the calculation for the 2017 test year calculation requirement and that the new projects should not be added.[528] OAG argues that Applicant failed to provide sufficient explanation for the new projects, and so they are unsupported.[529]

Analysis

Applicant provided evidence to support its original capital generation claims and subsequently explained changes to those claimed amounts.[530] The reasons for and impact of the changes were thorough, justified, and supported by cost analysis. However, the figures for the impact of the changes were not provided and Applicant holds that it is entitled to the revenue requirement calculation originally requested, despite the reduction in capital expenditures to date.

The change in the amounts is not significant, having an impact on revenue requirements less than $100,000. However, there is a change, and the analysis required of this tribunal and the PUC is to determine whether the rates are just and reasonable. This analysis is not based on the numbers alone, but includes examining the use of utility revenue. While it is true, as noted above, that projects may change without jeopardizing the funding necessary to pay for them, it is also true the new projects must be independently determined to be appropriate. In this case, the new projects are appropriate.

Conclusion

While Applicant should have updated the revenue requirement numbers based on the change in the value of the capital generation projects completed following the initial rate filing, the amount of change is so small that the change does not prejudice ratepayers in any aggregate sense. Applicant has shown all the projects and the costs are reasonable. Thus, no change in the calculation of the test year average is necessary based on this sub-issue.

iv. Storm Damage Amortization Expense

Deferred accounting is a regulatory tool used primarily to hold utilities harmless when they incur out-of-test-year expenses related to utility operations for which ratepayers have incurred costs or received benefits. These expenses are typically unforeseen, unusual, and large enough to have a significant impact on the utility's

[527] Ex. 46 at 8 (Skelton Rebuttal).
[528] Ex. 505 at 5 (Lee Direct); Ex. 507 at 13 (Lee Rebuttal).
[529] Ex. 505 at 5 (Lee Direct); Ex. 507 at 13 (Lee Rebuttal).
[530] Ex. 46 at 2-8 (Skelton Rebuttal).

financial condition. Such expenses may be eligible for rate recovery in the next rate caseare subject to review for reasonableness and prudence.[531]

Applicant sought to amortize $2,929,088 of incremental O&M expenses for 2016 storm repairs over four years starting in 2017.[532] The annual amortization expense adjustment is $732,272.[533]

Both OAG and the Department argue that the deferred accounting amortization request for 2016 storm costs should be removed from the test year because the PUC has already denied the request for such deferral and amortization.[534]

Applicant has removed the $732,272 annual amortization expense for the 2016 storm damage from the test year rate base. Thus, Applicant should be required to recalculate the test year average rate base with this amount removed.

v. Storm Restoration Budget

Positions of the Parties

Applicant requests $1,680,267 for the test year, based on actual 2016 costs for storm response costs.[535]

OAG argues that the claimed storm cost budget amount was not included in the initial filing and therefore should not now be considered.[536] OAG further argues that Applicant has not shown the new costs to be incremental, or distinct from the storm costs already included in the 2017 test year.[537] As a result, OAG argues the $1.68 million (total company) should not be permitted to be added to the test year.[538]

The Department agrees with OAG and believes Applicant's proposal for the storm response expense is unreasonable. First, the Department argues Applicant's recovery of the $1.68 million is unreasonable because it was not included in the initial revenue requirement deficiency.[539] Second, the Department argues that because $1.68 million is over double the $732,272 Applicant had initially sought in deferred accounting for 2016 storm costs, it is excessive.[540] Finally, according to the Department, "it is difficult to assess if these new storm damage expenses are actually incremental expenses, since two of the

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531 *In re Pet. for Approval of Deferred Accounting Treatment of Costs Related to the 2016 Storm Response and Recovery*, MPUC Docket No. E-015/M-16-648, Order Denying Petition for Deferred Accounting Treatment at 2 (Jan. 10, 2017).
532 Ex. 83 at 31 (Podratz Direct – Trade Secret).
533 *Id.*
534 Ex. 505 at 37-38 (Lee Direct).
535 Ex. 50 at 13 (Fleege Rebuttal); Evidentiary Hearing Tr. Vol. 4 at 125 (Campbell).
536 OAG Initial Br. at 15 (Sept. 12, 2017) (eDocket No. 20179-135457-02).
537 *Id.*
538 *Id.* at 16.
539 Ex. 630 at 70 (Campbell Surrebuttal).
540 *Id.* at 68.

largest incremental expenses[,] Paid Overtime and Contractors/Professional Services[,] are already in the 2017 Test Year at higher levels."[541]

Analysis

OAG and the Department urge a bright-line test in disallowing costs after the initial filing. The Administrative Law Judge disagrees, and recommends that the PUC adopt a case-by-case approach. While it is fair to expect an applicant to include all reasonably claimed costs in an initial filing, there may be situations where all reasonable costs for the test year are not possible to address at the time of filing.

Applicant did inform the PUC in its initial filing of its estimate, on top of the O&M budget, of incremental storm expenses. Applicant specifically stated it would update this information during the course of the case in rebuttal testimony. This it did once it had actual cost data to submit. The estimated amount turned out to be high. Could Applicant have handled this differently by actually including the estimate in the spreadsheets for the initial filing? Yes. But this does not mean the ultimate request is unreasonable. The evidence is based on a three-year average of actual costs up through 2016.

In this case, Applicant could have used the three-year average through 2015, because it had all of the actual costs for that period. It chose to wait for the 2016 data because that year included a rare storm that impacted Applicant's finances. Given that the storm was atypical, there is no other rational basis to wait for the 2016 numbers, other than to try again at obtaining additional recovery for those costs. However, in this case, even though a bright-line test for denying requests for expenses added after the initial filing is rejected, the circumstances do not warrant including the $1.68 million (total company) in the test year. A reasonable number could have been included in the initial request based on the most recent and available three-year data, but was not.

Conclusion

The PUC should not adopt a bright-line test for rejecting expense recovery requests that are made following the initial petition. There may be situations where such late filing is warranted.

The PUC should reject the addition of the $1.68 million (total company) for storm expenses because it was late, it was based on an unusual storm year, and because the PUC previously rejected Applicant's attempt to recover the claimed storm damage costs. As a result, Applicant should be required to recalculate the test year average based on this recommendation.

vi. Sappi/Cloquet Generator Amortization Expense

Applicant had included $232,618 in the test year as a deferred amortization expense for the Sappi/Cloquet Turbine TG5 generator. Applicant had initially sought

[541] Department Initial Br. at 34 (Sept. 12, 2017) (eDocket No. 20179-135469-01).

permission from the PUC for deferred accounting for treatment of costs related to the depreciation expense of this generating until in Docket No. E015/M-16-876.[542] Applicant subsequently withdrew this request, with PUC approval.[543] Applicant no longer owns this generating unit.[544]

Following objections from OAG and the Department based on the Applicant's lack of approval for deferred account of the amortization expense for Sappi/Cloquet Generator TG5, Applicant removed the $232,618 requested from the test year rate base.[545] This sub-issue requires no further consideration.

vii. Credit Card Processing Fees

Positions of the Parties

Applicant requests to include credit and debit card fees, charged by banks when customers pay with credit or debit cards, in its general costs of doing business.[546] Applicant estimates they must pay banks and their electronic payment processing vendor $350,000 during the test year for such fees.[547] This estimation includes an assumption that credit and debit card payments for electric service will increase from five percent to 15 percent.[548]

OAG argues that Applicant should be required to explore more cost-effective means of accepting credit and debit card payments from customers.[549] However, according to OAG, the use of a third-party vendor to process such payments rather the accepting such payments directly does not address this cost issue and only spreads the cost of the vendor to all customers, whether or not they use a credit or debit card.[550] According to OAG, while reducing payment costs is good, Applicant has not provided evidence of cost savings. It has only proposed to transfer the payment processing vendor's costs to all customers.[551] If Applicant is to take advantage of payment processing efficiencies, it must provide evidence demonstrating that cost savings, according to OAG.[552] Thus, based on the evidence presented by Applicant, OAG recommends the $350,000 cost of processing credit and debit card payments should be removed from the 2017 test year base rates.[553]

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542 Ex. 629 at 7 (Campbell Direct).
543 *Id.* at 8.
544 Ex. 83 at 29 (Podratz Direct).
545 Ex. 86 at 7-8 (Podratz Rebuttal).
546 Ex. 76 at 28 (Koecher Direct).
547 *Id.* at 31; Ex. 77 at 24 (Koecher Rebuttal); Ex. 83 at 32 (Podratz Direct).
548 Ex. 76 at 32 (Koecher Direct).
549 Ex. 505 at 41-42 (Lee Direct).
550 *Id.*; Ex. 508 at 5-7 (Lee Surrebuttal).
551 Ex. 505 at 41-42 (Lee Direct); Ex. 508 at 5-7 (Lee Surrebuttal).
552 Ex. 505 at 41-42 (Lee Direct); Ex. 508 at 5-7 (Lee Surrebuttal).
553 Ex. 505 at 42 (Lee Direct); Ex. 508 at 6 (Lee Surrebuttal).

The Department does not believe costs for the processing of credit and debit card payments should be removed from the customers who rely on such means of payment.[554] According to the Department, customer satisfaction cannot take precedent over proper allocation of costs to parties that cause Applicant to incur them. As a result, the Department argues $350,000 should be removed from the rate base for the 2017 test year.[555]

Analysis

All of the parties arguing on this sub-issue raise valid points. Applicant's effort to improve customer service and satisfaction is important. OAG's concern about Applicant's failure to provide clear evidence about cost savings for itself and ratepayers is also valid. Further, the Department's position that to shift convenience costs from those customers who use a particular service to all customers is not fair warrants attention.

The Administrative Law Judge largely agrees with OAG that while reducing costs is valid and important to both Applicant and customers, Applicant has not provided clear evidence on cost savings. Applicant outright rejects processing such payments directly, instead relying on an outside vendor whom it has agreed to pay $2.95 per transaction.[556] While this expense is likely smaller than what it costs to handle a paper check, Applicant has provided no clear evidence on such important questions. Additional questions remain, such as: Who processes checks? What is the cost of ACH payments? What would it cost for Applicant to accept credit and debit cards directly, both initially in setting up a system and over time?

However, the argument against having all customers pay the expense for those customers who pay by credit or debit card is unavailing. All forms of payment incur a cost, whether internally, externally, or both. With checks there is the time involved in all the various stages from the time the check is written by the customer to when the payee receives the promised funds. There is the staff and machinery necessary to receive and handle mail and the checks inside. There is the process of either imaging the checks or physically delivering the checks to the bank. Thus, there is a cost for Applicant and customers, but it is currently unknown how much or who is paying. Presumably, all customers are incurring the costs for processing the approximately 600,000+ checks Applicant receives from customers annually.[557] Thus, having more customers move from high-cost payment methods to more efficient ones is important to all involved. To help this evolution, the PUC should permit a portion of the claimed costs for processing credit and debit card payments so that those transactions increase, while forcing Applicant to look more closely at cost savings.

Conclusion

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[554] Ex. 614 at 13 (Zajicek Direct); Ex. 616 at 10-11 (Zajicek Surrebuttal).
[555] Ex. 614 at 14 (Zajicek Direct); Ex. 616 at 11 (Zajicek Surrebuttal).
[556] Ex. 77 at 24 (Koecher Rebuttal).
[557] *See* Ex. 76 at 31, Fig. 10 (Koecher Direct).

Applicant's request to include $350,000 into the 2017 test year base rates for the purpose of covering the costs of credit and debit cards fees should be denied. However, reducing the overall costs of payments for service should be encouraged. Further, it is presumed that typically the costs of payment are borne by all involved, including Applicant. Thus, it is recommended that $175,000 be included in the test year base rates and that Applicant be directed to more thoroughly explore efficient payment mechanisms, including accepting credit and debit cards directly and providing a report to the PUC in its next rate review case.

Applicant should be required to recalculate the test year average based on this recommendation.

viii. Charitable Contributions and Administrative Costs of Minnesota Power Foundation

Positions of the Parties

Applicant includes $394,280 in the test year rate base for charitable contributions.[558] This amount claimed is based on an average of 50 percent of the annual qualified charitable contributions for the three years 2013 through 2015.[559] The contributions to the Foundation were budgeted for 2017 at $512,000 (total company), but this was reduced to $453,128 (total company) due to expected lower operating income.[560] Applicant also includes $114,597 for the administration of its charitable Foundation, which distributes the charitable funds.[561]

OAG argues that Applicant used the wrong three year period to average its charitable contributions. OAG believes Applicant should have used 2014, 2015, and 2016.[562] This is because the test year is 2017 and there is great variability from year to year in charitable contributions.[563] The average for this time period is $825,865 (total company).[564] The permitted recoverable amount would be $412,933 (total company).[565]

The Department argues that the administrative costs of operating Applicant's Foundation for distributing charitable funds should be excluded from the test year base rates. The Department argues these costs should be excluded because the PUC has historically excluded the items from the rate base.[566]

Analysis

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[558] Ex. 17, Sched. A-6 at 1 (Supplemental Direct Filing Vol. 2); Ex. 83 at 23 (Podratz Direct).
[559] Ex. 17, Sched. A-6 at 1 (Supplemental Direct Filing Vol. 2); Ex. 83 at 23 (Podratz Direct).
[560] Ex. 17, Sched. A-6 at 1 (Supplemental Direct Filing Vol. 2); Ex. 83 at 23 (Podratz Direct).
[561] Ex. 626 at 3, LL-1 (La Plante Direct).
[562] Ex. 505 at 45 (Lee Direct).
[563] *Id.* at 43-46.
[564] *Id.* at 46.
[565] *Id.* Approximately $359,250 for Minnesota Jurisdiction.
[566] Ex. 626 at 3-5 (La Plante Direct).

Applicant filed the application for the increase in rates on November 2, 2016. It did not yet have the total amount of charitable giving for that year.[567] It used the three most recent years with complete accounting: 2013, 2014, and 2015.[568] This was entirely reasonable and consistent with the PUC's directive of November 2, 2010, when it required Applicant to use a three-year average rather than a single year for calculating a reasonable amount for recoverable test year charitable expenses.

With regard to the administrative costs of administering its charitable giving, the Department is correct that the PUC has agreed with the Department in other cases that such costs are too far "removed from the contributions" which are permitted to be recovered at 50 percent.[569] The PUC has determined that where an applicant "has not demonstrated that it is reasonable or consistent with the public interest to charge the Foundation's administrative costs to ratepayers as a part of the cost of furnishing electric service" such costs are excluded in favor of the consumer.[570]

However, in this case, Applicant has shown it is reasonable and consistent with the public interest to charge the administrative costs of its charitable giving to ratepayers, in part. For example, in 2015 Applicant made 241 contributions to nearly as many different organizations within its service territory.[571] This represents a tremendous amount of philanthropic outreach to its community and for permitted purposes under Minn. Stat. § 216.16B, subd. 9. While 50 percent of these donations are recoverable under statute, the statute is silent as to the administrative costs. Because of the importance of the philanthropy to the community of ratepayers, and because such philanthropy is reduced if the ratepayers are the ones to pay for it all, it is reasonable and just to follow the legislature's lead in equally allocating the charitable contributions between ratepayers and the company and its shareholders and apply this 50 percent allocation to the administrative costs of managing those hundreds of contributions.

Conclusion

Applicant has met its burden to demonstrate its recoverable amount of charitable donations of $394,280 for the test year. Applicant has not demonstrated it is entitled to recovery of 100 percent of the costs of administering that charitable giving. The Administrative Law Judge respectfully recommends the PUC permit recovery of $57,298, or 50 percent, of those costs. Applicant should be required to recalculate its test year average based on these recommendations.

ix. Travel, Entertainment, and Related Employee Expenses

[567] Ex. 33 at 26 (McMillan Rebuttal).
[568] Minn. R. 7825.3100, subp. 10 (2017), defines "most recent fiscal year," which includes 2016 in this case. However, there is no requirement that the most recent fiscal year, as defined by the rule, be used for the calculation of the average.
[569] Ex. 626 at 4 (La Plante Direct).
[570] *In re Application of N. States Power Co., a Minn. Corp., for Auth. to Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E002/GR-08-1065, Findings of Fact, Conclusions of Law and Order at 23 (Oct. 23, 2009).
[571] Ex. 6, Sched. G-2 (Initial Filing Vol. 4).

a. Membership Dues

Positions of the Parties

Applicant is seeking to include $772,448 (total company) in the test year for membership dues.[572] This is $17,514 (total company) less than requested in its initial filing due to the identification of that amount for lobbying activity.[573] Applicant is not seeking to recover money spent on, or for, the purpose of lobbying.[574] Applicant provided evidence of the work engaged in by all of the organizations it is seeking recovery of membership dues for.[575] Applicant provided specific explanations for the purpose of three organizations in relation to Applicant's business: Edison Electric Institute; National Hydropower Association; and Western Coal Traffic League.[576]

OAG argues that an additional $400,671 should be disallowed from the expenses for membership dues.[577] Specifically, OAG argues there are 11 organizations for which membership dues should not be recovered:

- Edison Electric Institute + USWAG & UARG
- Western Coal Traffic League
- Utility Water Act group
- Mining Minnesota
- Minnesota Forest Industries
- Minnesota Timber Producer Association
- National Association of Manufacturers
- American Wood Protection Association
- National Coal Transportation Association
- World Steel Dynamics Incorporated
- National Hydropower Association[578]

OAG argues these organizations are primarily engaged in lobbying and advocacy work.[579] OAG argues that organization invoices which rely on the Internal Revenue Service (IRS) definition of lobbying and political expenditures are suspect because the IRS definition is not applicable to ratemaking.[580]

[572] *Id.*, Sched. G-3; Ex. 55 at 19 (Morris Rebuttal).
[573] Ex. 55 at 19 (Morris Rebuttal).
[574] *Id.* at 13.
[575] Ex. 55 at 15-17, SWM-3, SWM-4 (Morris Rebuttal).
[576] *Id.* at 15-17.
[577] OAG Initial Br. at 28-29, 34 (Sept. 12, 2017) (eDocket No. 20179-135457-02).
[578] *Id.* at 28.
[579] *Id.* at 29-30.
[580] *Id.* at 31-33.

Analysis

On June 14, 1982, the PUC issued a non-binding statement of policy requesting data from applicants regarding dues expenses.[581] The information the PUC requests utilities provide in initial filings are:

- Each individual organization claimed for ratemaking purposes;
- The number of employees for which memberships are paid;
- The corresponding dollar amount of dues;
- An explanation of the primary purpose of the organization, specifically whether that is:
    - educating and informing public utility employees about providing improved utility services;
    - training employees to become better qualified in providing improved utility service;
    - membership in the organization is a necessary qualification for public utility employees to carry on their employment responsibilities; or
    - the membership provides essential information to the utility.[582]

The PUC adds, consistent with Minn. Stat. § 216B.16, subds. 4, 6, and 17, that it cannot "impose on customers the expense of dues when it has not been shown that customers receive any benefit from the organization receiving the dues[.]"[583]

Applicant provides a spreadsheet of organizations to which it pays membership dues. There are two lists: one for corporate memberships and one for employee memberships. With regard to each organization, the amount of the 2015 dues is recorded. For the list of employee memberships, the list includes the number of employees for whom membership dues are claimed. Then the spreadsheet includes a code. The code corresponds to a reason Applicant is a member. There are four reasons listed, corresponding to the four reasons the PUC has stated it is looking for in approving dues expenses.[584]

Applicant provided testimony about the purposes of only three organizations: Edison Electric Institute; National Hydropower Association; and Western Coal Traffic League. The explanations demonstrate that the non-lobbying portion of the cost of dues in these organizations, $417,946, should be recoverable and included in the test year.[585]

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[581] Ex. 8, Sched. ADJ-IS-15 (Initial Filing Vol. 5).
[582] *Id.*
[583] *Id.*
[584] Ex. 6, Sched. G-3 (Initial Filing Vol. 4).
[585] This figure is the sum of the 2015 amounts for the three organizations, including all five components of EEI ($478,821), minus the amounts allocated to non-regulated and subsidiaries ($17,032), minus the amounts not deductible as lobbying expenses ($43,843).

The PUC has provided explicit instruction on how a utility can make its case with regard to recovery of membership dues. Applicant has not complied with the instruction and has not met its burden of proof with regard to the majority of organizations for which it seeks recovery of corporate and employee memberships. For the majority of organizations, Applicant merely states whether the organization's primary purpose is: "educating and informing public utility employees about providing improved utility services"; "training employees to become better qualified in providing improved utility service"; membership in the organization is a "necessary qualification for public utility employees to carry on their employment responsibilities"; or the "membership provides essential information to the utility." [586] These are conclusions, not explanations.

Applicant has provided evidence of each organization's purpose. This, likewise, does not satisfy its burden of proof. It is not the duty of the tribunal or the PUC to research each organization Applicant pays dues to and guess as to how or whether that membership benefits ratepayers. In the three situations where Applicant provided such explanation, the burden of proof has been met, despite arguments by OAG. However, the remaining dues requests are only partially supported and the Administrative Law Judge cannot recommend they be included because they lack justification of the benefit to ratepayers.

Conclusion

Applicant has met its burden of proof with regard to the membership dues for: Edison Electric Institute; National Hydropower Association; and Western Coal Traffic League. This totals $417,946.

Applicant failed to meet its burden of proof with regard to the remainder of claimed membership dues. It did not provide the rationale for membership as to each organization or how the money spent on membership would benefit ratepayers. Thus, the remainder the requested amount, $808,043 should be excluded from the test year. OAG's detailed arguments about the break downs of membership fees permitted are unconvincing and do not weigh against recovery of the $417,946.

Applicant should be required to recalculate its test year average to refelct these recommendations.

b. Employee Gifts

Positions of the Parties

Applicant seeks to recover $23,007 (total company) for employee gifts in the test year.[587] The gift expenses only relate to safety awards and length-of-service and

[586] Ex. 6, Sched. G-3 (Initial Filing Vol. 4).
[587] Ex. 55 at 20 (Morris Rebuttal).

retirement awards in the form of gift cards.[588] The amounts of the gifts are set by company policy and are designed to support employee recognition and service recognition.[589]

OAG argues that all requested recovery for employee gifts should be eliminated because Applicant has not shown they are necessary for the provision of utility service.[590]

Analysis

Employee gifts are one of the expenses the legislature has authorized the PUC to permit utilities to recover from ratepayers.[591] In order to be recoverable, gift expenses must be reasonable and necessary for the provision of utility service.[592] The utility must include in its petition to authorization to increase rates a schedule itemizing the gift expenses.[593] The itemization must include: the date of the expense; the amount; the vendor name; and the business purpose.[594]

Applicant has a policy on employee recognition gifts, bonuses, and awards.[595] The policy, included in the Employee's Handbook, refers to employee recognition gifts that are "appropriate and reasonable for the work performed and meaningful to the employee."[596] "Employee recognition, gifts, and bonuses include High Performance Awards, Extraordinary Compensation, Spot / Project Bonuses, Gift Cards, Non-Monetary Gifts and Safety Awards, Special Time Off with Pay, Recognition Meals and Events, and other employee recognition."[597] With regard to safety awards, the policy is that:

> An individual's safety award cannot exceed $400. If awards exceed these limits, they must be considered taxable. The safety award items must be of tangible personal property and awarded in a meaningful presentation.[598]

Retirement and service awards are administered by ALLETE's human resources department.[599] "Service and retirement are determined according to set procedures and policies of Human Resources based on length of service and are, therefore, considered non-discretionary."[600] The record lacks detail about these procedures and policies.[601]

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588 Ex. 505, SL-19 at 2-3 (Lee Direct).
589 *Id.*
590 *Id.* at 60-64; Ex. 508 at 16 (Lee Surrebuttal).
591 Minn. Stat. § 216B.16, subd. 17(a)(7) (2016).
592 *Id.*, subd. 17(a).
593 *Id.*
594 *Id.*, subd. 17(b).
595 Ex. 53, SWM-9 at 14-17 (Morris Direct).
596 *Id.* at 14.
597 *Id.* at 14-15.
598 *Id.* at 16.
599 *Id.* at 17.
600 Ex. 505, SL-19 at 2-3 (Lee Direct).
601 *See, e.g.,* Ex. 53, SWM-11 (Morris Direct); Ex. 55 at 20-21 (Morris Rebuttal); Ex. 56 at 3 (Johnson Direct); Ex. 58 at 37 (Johnson Rebuttal).

Applicant offers valid reasons for providing employee gifts, including safety awards, service and retirement awards. Applicant provided a schedule of gifts expenses for 2015.[602] The spreadsheet includes the date of each gift expense, the amount, the vendor name, and a brief description of the expense item.[603] The purpose of these expenses is to support employee retention and rewarding, if not at least recognizing, longevity of employee service. While Applicant has withdrawn its initial request for recovery for additional employee gifts for exceptional performance, the Administrative Law Judge recommends the PUC consider permitting additional recovery in the test year for those expenses, too.

Conclusion

Applicant established the necessity and reasonableness of the expense of $23,007 (total company) for employee gifts in the test year. The Administrative Law Judge recommends this amount, at a minimum, be included in the test year rate base. No recalculation is necessary.

x. Remaining Expenses – Calculation of Rate Base

Positions of the Parties

Applicant created its overall employee expense budget for the test year through process that relied on input from each Responsibility Center of the company and used the most recently completed fiscal year data.[604] Each Responsibility Center projected the amount of employee expenses it expected and these values were combined in an overall employee expense budget.[605] That total was $6,373,590 (total company).[606] Applicant then analyzed 2015 employee expense data to identify expenses to exclude from the test year budget.[607] Some incurred expenses were excluded. For example, expenses with a vague business purpose; employee recognition expenses (except for safety achievement recognition); foreign travel (except when related to utility operations); lobbying; and 50 percent of investor relations; among others.[608] This analysis resulted in a reduction of the test year budget by $1,620,291, for a total of $4,753,299.[609] This is the amount Applicant is seeking to include in its base rate for the test year.[610]

OAG argues that the remaining expenses under Minn. Stat. § 216B.16, subd. 17 should be determined using a three-year average.[611] OAG believes using a three-year average will better represent the reasonable travel, entertainment, and related employee

[602] Ex. 6, Sched. I (Initial Filing Vol. 4).
[603] *Id.*
[604] Ex. 55 at 2 (Morris Rebuttal).
[605] *Id.*
[606] *Id.* at 3.
[607] *Id.*
[608] *Id.*
[609] *Id.*
[610] *Id.*
[611] Ex. 505 at 68-73 (Lee Direct).

expenses in the test year.[612] A properly calculated three-year average would be $3,056,816.[613] This is based on subtracting unrecoverable 2015 actual expenditures (provided by Applicant), calculating a ratio of unrecoverable expenses (based on those withdrawn by Applicant from its initial request), and applying that ratio to both 2014 and 2016 and averaging all three years (2014, 2015, and 2016).[614] OAG also argues that there were $27,520 (total company) worth of employee expenses itemized that did not include a vendor name.[615] OAG argues this amount must be removed from the rate base for the test year because it does not meet the requirements of Minn. Stat. § 216B.16, subd. 17(b).[616]

Analysis

Minnesota Statute §216.16, subd. 17 provides direction on recovery of travel, entertainment, and related employee expenses. Minn. Stat. § 216B.16, subd. 17(b) expressly requires itemization that includes, among other things, the name of the vendor to whom the expense is paid.[617] More importantly, the itemization must convey the business purpose of the expense.[618] While a utility may use "standard accounting reports already utilized by the utility[,]" the reports must include the required information and be acceptable to the PUC.[619] The law does not prescribe a particular method for making determinations about how a test-year is devised, however.

Applicant has shown it used a reasonable method to determine the amount of travel, entertainment, and related employee expenses. It has also demonstrated that this method resulted in a reasonable and necessary amount, minus those expenses that it has not fully supported.

Applicant did not include the data necessary to determine the business purpose of expenses in every itemization. Even if the vendor is easily identified, Applicant has not always met this requirement. The vendor name may help understand the business purpose of the expense, but not always. For example, the particular vendor operating a parking ramp (many of the expenses were for parking) will not aid the PUC in understanding the business purpose of the claimed expense. Where the vendor is not identified, or is only listed as the employee, and there is insufficient data to clearly indicate the business purpose of the expense, Applicant has not met this requirement and the itemized expense should not be permitted. In Docket No. E017/GR-15-1033 the PUC found that the utility had provided sufficient information to identify the business purposes of the challenged employee expenses.[620] Here, in reviewing Ex. 505, SL-23 and the

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[612] *Id.* at 67.
[613] *Id.* at 73.
[614] *Id.* at 72-73.
[615] *Id.*, SL-23 at 54-66.
[616] *Id.* at 76.
[617] Minn. Stat. § 216B.16, subd. 17(b).
[618] *In re Application of Otter Tail Power Co. for Auth. To Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E017/GR-15-1033, Findings of Fact, Conclusions, and Order at 45, 47 (May 1, 2017).
[619] Minn. Stat. § 216B.16, subd. 17(b).
[620] *In re Application of Otter Tail Power Co. for Auth. To Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E017/GR-15-1033, Findings of Fact, Conclusions, and Order at 47 (May 1, 2017).

explanations provided by Applicant (see Ex. 55 at 8-11 (Morris Rebuttal)), it is not always clear what the business purpose of the expense being reimbursed is. Thus, Applicant has not met its burden of proof and the $27,520 (total company) of expenses, minus any that include sufficient information to identify its legitimate business purpose, should be denied.

Conclusion

The Administrative Law Judge recommends that the PUC approve Applicant's method of calculating travel, entertainment, and related expenses (not including the separately addressed membership dues and gifts). It is recommended the PUC deny employee expenses for which a legitimate business reason cannot be determined.

Applicant should be required to recalculate its test year average to reflect these recommendations.

xi. Prepaid Pension Asset

Positions of the Parties

Applicant seeks recovery of $27,816,947 for its prepaid pension asset. This is part of Applicant's actual 2017 pension expense.[621] The prepaid pension asset is the contributions to the pension which exceed the expenses drawn from the pension plan.[622] Currently, Applicant is recovering an amount of pension expense based on a five-year average that was calculated in its 2009 rate case.[623] There is a question of whether it is fair to permit Applicant to earn a return on the prepaid pension asset.

The Department argues that Applicant's request for recovery of its prepaid pension asset should be rejected. The PUC has ruled similarly in in recent and litigated cases concerning requests to recover prepaid pension assets, according to the Department.[624] According to the Department, balances in a prepaid pension asset are temporary, and fundamentally different from typical rate-base assets on which Applicant earns a return on investment.[625]

Analysis

While Applicant makes some compelling arguments for including the prepaid pension asset in its rate-base, this case is not significantly different from prior cases in which the PUC has considered this issue. Applicant argues that it is incorrect to state that the prepaid pension asset is temporary and that it is actually one of the most permanent assets a utility can have, outside of unimproved land.[626] But the substance of the PUC's previous rulings against recovery for prepaid pension assets is that the asset, unlike plant,

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[621] Ex. 37 at 63 (Cutshall Direct).
[622] *Id.* at 61.
[623] *Id.* at 63.
[624] Department Initial Br. at 30-31 (Sept. 12, 2017) (eDocket No. 20179-135469-01).
[625] *Id.* at 31.
[626] Ex. 38 at 38 (Cutshall Rebuttal).

oscillate in value from year to year and it is next to impossible to discern whether the changes in value come from shareholder dollars, marketplace returns, or changes in actuarial accounting.[627]

Conclusion

The Administrative Law Judge recommends that the prepaid pension asset not be included in the test year rate base for the reasons the PUC has described in prior cases. It is impractical, if not impossible, to attribute specific sources for the changes in value to such an asset. Thus, it is not reasonable to require rate-payers to fund it. The 2017 rate base should be reduced $27,816,947 and Applicant should be required to recalculate its test year average to reflect these recommendations.

xii. High-Level Employee Related Expenses

Positions of the Parties

Applicant seeks to include in the test year rate base expenses for certain high-level employee compensation. Specifically, Applicant seeks to include its two non-qualified deferred compensation (NQDC) plans: Executive Deferral Account (EDA) and Executive Investment Plan (EIP); and its Annual Incentive Program (AIP). The NQDC plans provide management-level employees the opportunity to save for retirement through a salary or bonus deferral which are above IRS limitations on contributions to qualified deferred compensation plans.[628] EDA is for current management-level employees, and EIP is for retired management-level employees.[629] AIP is an incentive plan offered to 190 supervisory or other key employees to supplement their base pay to make it more in-line with market pay rates and obtain higher performance from them.[630] Applicant seeks to include $1,160,890 in the test year rate base for EDA expenses and $150,097 for EIP expenses.[631] Applicant seeks to include $2,722,990 (total company) in the test year rate base for AIP.[632]

Applicant argues that these expenses are reasonable and necessary because they are a crucial element of its overall benefit package to attract and retain qualified management-level employees.[633] Applicant argues that these benefits are in line with prevalent benefits in the marketplace.[634] According to Applicant, skilled and effective management-level employees are critical to the day-to-day operations of the company because these employees are responsible for the supervision, engagement, and training

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[627] *See, e.g., In re Application of Otter Tail Power Co. for Auth. To Increase Rates for Elec. Serv. in Minn.,* MPUC Docket No. E017/GR-15-1033, Findings of Fact, Conclusions of Law, and Order at 25 (May 1, 2017).
[628] Ex. 56 at 50-51 (Johnson Direct); Ex. 58 at 23-24 (Johnson Rebuttal).
[629] Ex. 58 at 24 (Johnson Rebuttal).
[630] Ex. 56 at 13, 17 (Johnson Direct).
[631] Ex. 58, NRJ-4 (Johnson Rebuttal).
[632] Ex. 56 at 20 (Johnson Direct).
[633] Applicant Initial Br. at 64 (Sept. 12, 2017) (eDocket No. 20179-135459-02).
[634] Ex. 58 at 25 (Johnson Rebuttal).

of other employees to provide safe and reliable electric service at a reasonable cost.[635] Applicant argues that a cost/benefit analysis of the precise quantification of the benefits of fairly compensating and successfully retaining employees through the plans is not reasonable.[636]

Applicant also argues that its Annual Incentive Plan (AIP) is a necessary and reasonable expense that should be part of its test year rate base. According to Applicant, the AIP allows Applicant to manage the compensation of its management employees and to tie a portion of an employee's overall compensation to the achievement of company goals that benefit customers.[637] AIP applies to 16 percent of employees.[638] AIP is based on Applicant's achievement of six different goals in three areas: financial, strategic, and operational and values.[639] The metrics for the financial goals are total company net income and cash from operating activities.[640] According to Applicant, achievement of the financial goals requires prudent management of Applicant's expenses and reduces the cost of capital for utility operations, thereby providing a benefit to customers in the form of electric service at reasonable rates.[641] The metrics for the strategic goals are advancing Applicant's Energy*Forward* plan for affordable, reliable, environmentally sensitive performance and a modernized customer experience, as well as improved performance in earning the permitted long-term return on equity.[642] The metrics for Applicant's operational and values goals are reduced injuries and reduced unplanned outages with shorter durations.[643] The latter categories address clear customer benefits.

Applicant proposes to limit the level of incentive compensation to no more than 20 percent of individual base salaries.[644] Applicant argues that without AIP, total cash compensation for management level employees would be below the market median and it would be more difficult to recruit and retain quality leadership.[645] Ninety-nine percent of publically traded companies have short-term incentive plans, and 94 percent of privately held companies do.[646] Ninety-four percent of 17 electric utility companies near ALLETE's size offer short-term incentives as part of compensation.[647] The total cost of the AIP expense in the test year, including the 20 percent cap, is $2,722,990 (total company).[648]

The Department argues that Applicant has not met its burden because it has not provided a cost/benefit analysis to show how these costs provide a net benefit to

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[635] *Id.* at 24.
[636] Ex. 631 at 15, 17, DVL-11 (Lusti Direct); Applicant Initial Br. at 64 (Sept. 12, 2017) (eDocket No. 20179-135459-02).
[637] Ex. 56 at 17 (Johnson Direct).
[638] *Id.* at 3, 13. As of May 31, 2017, Applicant had 1,163 employees. *See* Ex. 58 at 2 (Johnson Rebuttal).
[639] Ex. 56 at 18 (Johnson Direct).
[640] *Id.;* Ex. 58, Table 2 (Johnson Rebuttal).
[641] Ex. 56 at 18 (Johnson Direct); Ex. 58 at 14 (Johnson Rebuttal).
[642] Ex. 56 at 18-19 (Johnson Direct).
[643] *Id.*
[644] *Id.* at 20.
[645] *Id.* at 17.
[646] *Id.* at 21.
[647] *Id.*
[648] *Id.* at 20.

ratepayers.[649] Applicant's narrative about the market competitiveness of its compensation and benefits in order to attract and retain employees is not sufficient, according to the Department.[650] Further, the Department argues that the PUC has previously determined that making ratepayers of investor-owned utilities cover the costs of benefits that exceed the deferral amounts permitted by the IRS is not reasonable.[651] As a result, the Department argues that $1,380,313 should be removed from the test year rate base.[652]

LPI argues that executive deferred compensation plans are a promise to pay future benefits that ratepayers should not be required to pay.[653] According to LPI, the fees associated with plan costs and the investment gains or losses resulting from the plans should be borne by the plan participants, not ratepayers.[654] According to LPI, the fees are typically removed from the investment or gains.[655] Removing the costs of the NQDC plans reduces the revenue requirement by $1.4 million, according to LPI.[656]

LPI also argues against recovery of the AIP expenses. According to LPI, incentives based on measurable operational goals can benefit ratepayers, but that incentives based on financial performance primarily benefit shareholders.[657] Improved financial performance increases dividends, value of stock, and reduces risk, according the LPI.[658] Thus, LPI argues financial performance based incentives should not be financed by ratepayers.[659] LPI argues that the cost of incentive programs based on financial achievement can be paid from the increased earnings.[660] Further, according to LPI, higher financial performance can be achieved at the expense of benefits to ratepayers, which would make having ratepayers fund the incentives unfair.[661]

LPI also argues that in Applicant's incentive plan, the strategic goals lack objective measurement, and also serve to improve return on equity.[662] Forty percent of AIP is weighted to strategic goals, and 50 percent is weighted to financial goals.[663] Only 10 percent is weighted to achieving the operational and safety goals which directly affect customers.[664] Thus, according to LPI, 90 percent of the API cost ($2.3 million) should be eliminated from the rate base in the test year.[665]

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[649] Department Initial Br. at 36-37 (Sept. 12, 2017) (eDocket No. 20179-135469-01).
[650] *Id.* at 37.
[651] Ex. 632 at 10-11 (Lusti Surrebuttal).
[652] *Id.* at 12, 33.
[653] Ex. 108 at 6 (Rackers Rebuttal).
[654] LPI Initial Br. at 10 (Sept. 12, 2017) (eDocket No. 20179-135470-02).
[655] Evidentiary Hearing Tr. Vol. 3 at 14 (Rackers).
[656] Ex. 108 at 8 (Rackers Rebuttal).
[657] Ex. 102 at 11 (Rackers Direct).
[658] *Id.* at 13.
[659] *Id.* at 11-13.
[660] *Id.* at 12.
[661] *Id.*
[662] *Id.* at 14.
[663] *Id.*
[664] *Id.*
[665] *Id.* at 15. This includes a reduction of 7.65% for payroll taxes.

Analysis

Applicant bears the burden of proving, by a preponderance of the evidence, that unless it provides non-qualified pension benefits and its incentive plan to its executives, it could not secure employees necessary to provide safe, reliable service. Applicant has shown that a large percentage of companies its size, including 17 utility companies close to its size, provide management-level employees non-qualified pension benefits as part of their compensation. Compensation and benefits is always a factor for potential and current employees of a business.[666]

While the opposition to Applicant's incorporation of the NQDC and AIP plans into base rates is reasoned and bears consideration, the arguments alone do not overcome the evidence Applicant has provided to show the inclusion of these costs are necessary and reasonable to provide safe and reliable electric service to its customers. Applicant has done a market analysis and provided other evidence showing how its compensation for higher-level employees, including executives, compares to organizations it is competing with for talent. No evidence to overcome Applicant's supported positions is in the record.

"Barring excessive compensation levels, skewed incentives, or other public policy concerns, the Company has the discretion to structure its compensation packages in accordance with its best business judgment."[667] A preponderance of evidence prevails over mere arguments of an academic or philosophical nature. For example, LPI makes a reasoned argument about who should pay for certain compensation for employees based on who gets the benefit: shareholders or ratepayers. In this case, both shareholders and ratepayers get the benefit of a well-managed organization that is operating in compliance with legal requirements. The act of dividing up the specifics of such variable benefits is not the work of an expert. Rather, it is the work of a philosopher, theologian, ideologue, partisan, or other person not fully possessed or perhaps concerned with the facts on the ground. The arguments presented include no evidence and are based on the application of the philosophies employed to show the Applicant is wrong. Mere philosophical differences, no matter how compelling or articulate, will not take the place of real evidence or properly legislated or promulgated policy.

The Department argues different evidence - a cost-benefit analysis - should have been conducted by Applicant to make its case. Merely arguing for different evidence does not demonstrate the evidence in the record is not a preponderance of evidence. Most importantly, there has been no evidence provided by the opposition to these plans showing that Applicant's claims and evidence about fair compensation for its high-level employees is not accurate. Thus, Applicant's position must prevail.

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[666] *See, e.g., In re The Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, MPUC Docket No. E-002/GR-12-961, Findings of Fact, Conclusions of Law, and Recommendations at 42 (July 3, 2013) ("To provide safe and reliable service, the Company needs to be able to offer competitive compensation packages to its employees.").

[667] *In re Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E-015/GR-09-1151, Findings of Fact, Conclusions, and Order at 29 (Nov. 2, 2010).

Conclusion

Applicant's position for high-level employee compensation is just and reasonable and is supported by evidence. The objections to the compensation expenses are not supported by evidence. Thus, the Administrative Law Judge recommends that Applicant's inclusion of the costs for its NQDCs and AIG be included in the test year rate base.

xiii. Unfilled Positions

Positions of the Parties

Applicant proposed a 2017 test year cost of employee compensation of $82,621,828 on a total Company basis.[668] In the course of its investigation of Applicant's rate case, however, the Department determined that Applicant's proposed test-year cost for compensation included compensation for positions that were unfilled. Applicant used a count of 1,202 full-time equivalent employees (including 482 bargaining unit employees and 720 non-bargaining unit employees) to develop the 2017 test year expenses.[669] But, Applicant had 46 unfilled positions during January 2017, 51 during February, and 45 each during both March and April 2017. These amounts represent 3.82%; 4.25%; 3,74% and 3.74% under budget, respectively, for the months of January through April 2017.[670]

The Department recommended an adjustment in an amount equal to an average under-budget amount of 3.89 percent, which was both the four-year average under-budget for the years 2013, 2014, 2015 and 2016; as well as the average under-budget for the months of January, February, March and April of 2017.[671] Applicant proposed to reduce the $82,621,828 test-year compensation cost by $2,662,793 on a Minnesota Jurisdictional basis, to account for unfilled positions, calculated by using the actual head-count differences for the first five months of 2017, and using the actual May 2017 head count for the remaining seven months of 2017, which yielded a reduction to the test-year head count of 3.46 percent.[672] In addition, Applicant calculated a related adjustment that reduced the associated employment benefits by $306,828.[673] Thus, Applicant's total proposed adjustment for unfilled positions reduced compensation and related benefits was $2,969,621 on a Minnesota Jurisdictional basis.[674] The Department agreed this is reasonable and should be approved by the PUC.[675]

Conclusion

Applicant's test year average should be recalculated, in part, based on the agreement of Applicant and Department to adjust Applicant's initial employee compensation request by $2,969,621.

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[668] Ex. 631 at 24 (Lusti Direct).
[669] Ex. 56 at 3 (Johnson Direct); Ex. 631 at 23 (Lusti Direct).
[670] Ex. 631 at 23, DVL-17 (Lusti Direct).
[671] *Id.* at 24.
[672] Ex. 58 at 6 (Johnson Rebuttal).
[673] *Id.*
[674] *Id.*; Ex. 632 at 19 (Lusti Surrebuttal).
[675] Ex. 632 at 20 (Lusti Surrebuttal).

xiv. Test Year Cash Working Capital (CWC)

Positions of the Parties

CWC represents an amount of cash needed to meet current operating expenses incurred prior to collecting revenues for the service provided.[676] The requested CWC is adjusted to reflect the impact of various O&M expense adjustments to the test year budget, including those required by PUC policy for advertising expense, economic development, charitable contributions, and organizational dues.[677] In addition, state and federal income taxes in CWC reflect interest synchronization and the tax impact of the revenue deficiency.[678]

The most precise method of determining CWC requirements is to perform a lead/lag study.[679] A lead/lag study measures the difference between the period of time the utility has to pay for the expenses to provide service to customers (expense lead) and the period of time it takes the utility to collect revenues from its customers (revenue lag).[680] Applicant prepared a lead/lag study in 2012 and the resulting capital calculation was consistent with the approach and methodology filed by the company and approved by the Commission in Docket No. E015/GR-09-1151, based on a 2006 lead/lag study.[681]

LPI argues Applicant's lead-lag study is incomplete because it does not include interest expense, a significant cost of service.[682] According to LPI, including interest expense in the lead/lag study is wholly separate from recognizing interest synchronization, which the Applicant relies upon here.[683] LPI argues that the concept of interest synchronization assumes that the level of interest expense in the rate of return for a utility should be the same as the interest expense in the income tax expense of the utility.[684] Interest expense is a known and certain obligation of the company established by the terms of the underlying debt instruments. Interest expense is collected through customer rates, as are the other expenses Applicant has recognized in its lead/lag study. The amounts collected for interest expense represent a source of cash to Applicant until payments are made to the bondholders. Therefore, according to LPI, interest should be included in Applicant's lead/lag study.[685] LPI argues that a pre-tax weighted average cost of capital of 10.30% should be used, resulting in a revenue requirement adjustment associated with the CWC requirement for interest expense of $0.8 million.[686]

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[676] Ex. 82 at 11 (Podratz Direct); Ex. 102 at 3 (Rackers Direct).
[677] Ex. 82 at 16 (Podratz Direct).
[678] *Id.*
[679] Ex. 102 at 3 (Rackers Direct); *see also* Ex. 82 at 11 (Podratz Direct).
[680] Ex. 102 at 3 (Rackers Direct).
[681] Ex. 82 at 11 (Podratz Direct).
[682] Ex. 102 at 3 (Rackers Direct).
[683] Ex. 111 at 4 (Rackers Surrebuttal).
[684] *Id.*
[685] Ex. 102 at 5 (Rackers Direct).
[686] *Id.* at 6.

Applicant argues that because it uses interest synchronization, as other utilities do and as the PUC has approved in the past, LPI's argument lacks merit.[687] Applicant argues that interest synchronization makes more sense than the approach advocated by LPI because Applicant has multiple bonds with staggered interest payment due dates during the year which generally match the revenue collections from customers on a monthly basis throughout the year. Thus, there is no issue making the monthly interest payments.[688]

The Department argues that as a result of the various Department adjustments to the test-year O&M expenses, test-year rate base, and the test-year capital structure, Applicant's CWC needs to be adjusted.[689] The Department calculated this adjustment by applying the Department's lead/lag days to the Department O&M expense adjustments. As a result of the various Department adjustments, the test-year CWC requirement should be decreased by $573,321.[690] According to the Department, if the PUC does not accept the Department's proposed rate base adjustments, revenue and expense adjustments, and capital structure in total, it will be necessary to recalculate the CWC to incorporate the effect of the approved rate base, revenue and expense adjustments, and the capital structure.[691] Similarly, if, as to some issues, financial information from the company arrived too late to incorporate into surrebuttal testimony, it may be necessary to recalculate the CWC to incorporate those adjustments.[692]

Analysis

Applicant's proposed lead/lag study and resultant CWC adjustment are reasonable. It is using a lead/lag study method, including interest synchronization, consistent with prior PUC determinations.[693] While this may be different from how some states conceive of, and use, interest synchronization (as a means solely to determine interest expense for the purpose of tax deduction rather than actual interest expense for ratemaking purposes), the PUC has approved of it for ratemaking purposes in Minnesota. Applicant has provided a rationale for doing so here. Thus, with appropriate adjustments to be made based on revisions in rate base, weighted cost of debt, and operations income, Applicant's method of determining CWC is reasonable.

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[687] Ex. 82 at 6 (Podratz Direct); Applicant Initial Br. at 88 (Sept. 12, 2017) (eDocket No. 20179-135459-02).
[688] Evidentiary Hearing Tr. Vol. 2 at 97-98 (Podratz).
[689] Department Initial Br. at 78 (Sept. 12, 2017) (eDocket No. 20179-135469-01).
[690] Ex. 632 at 8, 32, DVL-S-5 (Lusti Surrebuttal).
[691] *Id.*
[692] *Id.*
[693] *See In re Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E-015/GR-09-1151, Findings of Fact, Conclusions, and Order at 71 (Nov. 2, 2010); *In re Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, MPUC Docket No. E002/GR-15-826, Findings of Fact, Conclusions, and Order at 14, 66 (June 12, 2017).

Conclusion

The Administrative Law Judge recommends that the PUC accept Applicant's method for determining CWC. Applicant's CWC must be updated based on final adjustments made in this docket, and the CWC result of such changes should be incorporated into final rates. Further, because the actual level of the interest synchronization adjustment is dependent on the final outcome of rate base and interest adjustments, it is reasonable for Applicant to be required to recalculate this adjustment as part of its final compliance filing to reflect final rate outcomes in this proceeding.

xv. Production Tax Credits (PTCs) and Prorated Accumulated Deferred Income Taxes (ADIT)

The Department initially disagreed with Applicant's accounting of PTCs and its impact on the deferred tax expense credit.[694] However, Applicant and the Department ultimately agreed that a $1,462,487 reduction to deferred tax expense with a corresponding adjustment to ADIT, which will increase the rate base by $731,243.[695] This was based on using the new IRS 2017 PTC rate of $24/MWh.[696]

The Department and Applicant agree that final rates do not need to reflect prorated ADIT in order to avoid a tax normalization violation, but prorated ADIT is required for interim to avoid a tax normalization violation.[697] The basis for the agreement is an IRS private letter ruling (PLR) that was issued to another Minnesota public utility under similar facts and circumstances, namely, a rate case where the utility chose a future test year for the purposes of evaluating the reasonableness of the public utility's proposed rate increase.[698] While the Internal Revenue Code, to which PLRs specifically refer, states that PLRs are only issued to particular taxpayers and may not be used or cited as precedent by other taxpayers, the PLR issued to another Minnesota public utility under similar facts and circumstances provides persuasive value in this rate case as to the reasonableness of this agreement and recommendation. The agreement between Applicant and the Department is reasonable, including the calculations leading to the $731,243 increase in the rate base.

Applicant's test year average should be recalculated to reflect the $731,243 increase in the rate base.

xvi. Fuel Clause Adjustments

a. Fuel Clause Adjustment Methodology

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[694] Ex. 629 at 107-08 (Campbell Direct).
[695] Ex. 630 at 13–17 (Campbell Surrebuttal); Ex. 86 at 15 (Podratz Rebuttal); Ex. 75 at 2-5 (Jago Rebuttal).
[696] Ex. 75 at 5 (Jago Rebuttal).
[697] Evidentiary Hearing Tr. Vol. 1 at 197–99 (Jago).
[698] Ex. 74 at 9-12 (Jago Direct); Ex. 75 at 8-10 (Jago Rebuttal); Ex. 629 at 48-49 (Campbell Direct); Ex. 630 at 32-42 (Campbell Surrebuttal).

Applicant requests that decisions on the appropriate fuel clause calculation methodology be delayed until a decision is made *In the Matter of an Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments*, MPUC Docket No. E999/CI-03-803.[699] This is because the determination by the PUC in that docket will affect the fuel clause calculation methodology. Thus, the fuel clause calculation used by Applicant to arrive at the numbers for the fuel clause transition cost recovery and base cost of fuel requested by Applicant will be impacted.[700] The Department opposes a change to a new forecasted fuel clause adjustment methodology.[701]

Because Applicant has withdrawn its proposal for a forecasted fuel clause adjustment methodology, and seeks to defer to the PUC's methodology determination in Docket No. E999/CI-03-803, there is a potential timing problem. It is recommended that if a determination is made in that Docket, prior to the PUC's determination in the present case, the PUC require Applicant make new calculations based on its announced methods.

b. Fuel Clause Transition Cost Recovery

Applicant seeks to recover the amount of cost recovery that is stranded following a transition from a back-ward looking calculation methodology to the new method, yet to be determined by the PUC in Docket No. E999/CI-03-803.[702] However, Applicant also requested that a determination of the value of this cost recovery be delayed until the PUC determines the new methodology.[703] Applicant argues that it is entitled to "revenue sufficient to enable it to meet the cost of furnishing the service."[704]

The Department and LPI both object to Applicant's claim for recovery based on a fuel clause transition cost because, they argue, Applicant is not entitled to such a cost recovery. They maintain that Applicant is entitled to recover its "current period" cost of energy per kWh, not its actual energy costs per kWh.[705] According to the opposition, Applicant has recovered its current period cost of energy from ratepayers consistently over time.[706] They also insist that there is no support for Applicant's claim regarding a delay in the recovery of fuel costs.[707] The Department asserts that Applicant's claim rests on an unsupported assumption that exactly one-half of the difference between the estimated actual October 2017 energy cost and the base energy cost are "collected from customers on their December bills through the current fuel cost recovery method."[708] The Department argues that the cases Applicant relies on to support its position, Docket No.

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[699] Applicant Initial Br. at 89-93 (Sept. 12, 2017) (eDocket No. 20179-135459-02).
[700] *Id.*
[701] Ex. 72 at 6 (Oehlerking-Boes Direct); Ex. 624 at 23-26 (Ouanes Direct).
[702] Ex. 72 at 18 (Oehlerking-Boes Direct).
[703] Applicant Initial Br. at 90-92 (Sept. 12, 2017) (eDocket No. 20179-135459-02).
[704] *Id.*
[705] Ex. 624 at 4-13 (Ouanes Direct).
[706] *Id.* at 21; Ex. 100 at 7-8 (Gorman Direct).
[707] Ex. 624 at 20-22 (Ouanes Direct).
[708] *Id.* at 20.

E,G002/M-00-448 and Docker No. E002/M-00-420 are factually different and therefore irrelevant to the present case.[709]

Any calculations for the test year average made based on the recovery Applicant was initially seeking should be recalculated without the proposed fuel clause transition cost recovery.

c. Base Cost of Fuel

Positions of the Parties

Applicant requested that the base cost of fuel be changed from the 1994-set level of $10.18/MWh to $21.03/MWh.[710] This request was increased to $21.21/MWh during the course of these proceedings.[711] Now, Applicant requests the determination about the base cost of fuel be deferred until after the PUC makes a decision on methodology in Docket No. E999/CI-03-802.[712] This will, according to Applicant, avoid customer confusion that may result from two significant changes in a short time.[713] In the event the question is not deferred to Docket No. E999/CI-03-802, however, Applicant seeks the change to $21.21/MWh.[714]

The Department agrees that the base cost of fuel should be increased to $21.21/MWh and Applicant's cost factors updated.[715] This change would better reflect Applicant's annual energy costs, according to the Department.[716] Further, argues the Department, this will not adversely affect ratepayers because it will only increase the amount that ratepayers pay through base rates and would correspondingly reduce the amounts recovered through the FCA rider.[717] The Department does not take a position on deferral to Docket No. E999/CI-03-802. However, it maintains that if any additional significant adjustment to the base cost of energy occurs as a result of the present case (or the corresponding miscellaneous rate petition, *In the Matter of the Application of Minnesota Power for Approval of a New Base Cost of Fuel and Purchased Energy*, MPUC Docket No. E-015/GR-16-709) then the base cost of energy and the corresponding class-specific base cost of energy should be reflected in final rates.[718]

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[709] Department Initial Br. at 51-52 (Sept. 12, 2017) (eDocket No. 20179-135469-01).
[710] Ex. 72 at 3 (Oehlerking-Boes Direct).
[711] Ex. 84 at 12 (Podratz Supplemental Direct).
[712] Evidentiary Hearing Tr. Vol. 1 at 193 (Oehlerking-Boes).
[713] *Id.*
[714] *Id.* at 194.
[715] Ex. 625 at 13-14 (Ouanes Surrebuttal).
[716] *Id.*
[717] *Id.* at 5-6.
[718] Ex. 624 at 14 (Ouanes Direct).

Analysis

This matter is based on Applicant's petition for authority to increase rates. Thus, Applicant bears the burden of proof as to whether its proposals are just and reasonable.[719] While any other party to the proceeding may have a different or even better idea in how Applicant should manage its business, this alone will not overcome Applicant's position if it is supported by a preponderance of evidence that its proposal is just and reasonable. The Applicant has requested the determination about the base cost of fuel be deferred to Docket No. E999/CI-03-802 and a decision made there in order to avoid customer confusion that may result from two significant changes within a short period of time. There is no reason not to honor this request, regardless of other possible ways to deal with this issue.

Conclusion

The determination about the base cost of fuel should be deferred to Docket No. E999/CI-03-802. Alternatively, if amounts for the base cost of fuel are not deferred to another Docket, then it is recommended the base cost of fuel be increased to $21.21/MWh and incorporated into the base rates for the test year.

d. Chemical and Reagent Costs

Positions of the Parties

Applicant requests permission to include the cost of generation facility chemicals and reagents for environmental compliance.[720] This request was made because Minn. Stat. § 216B.16, subd. 7(4) permits the recovery of these expenses in the FCA rider.[721] Applicant argues that the costs of these chemicals and reagents are incurred to support the self-generation of electricity for its customers.[722] The test year cost of reagents is $4,000,954, and is currently part of the O&M budget.[723]

The Department objected to including these costs in the rider, arguing instead that they be included in base rates.[724] The Department argued that permitting recovery through the rider will reduce Applicant's "incentive to minimize these costs."[725] The Department argues that the PUC has not opted to follow the authorization provided it by the legislature in permitting the recovery of chemical and reagent costs in the fuel clause. It points to the holdings in *In re Application of Otter Tail Power Co. for Auth. To Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E017/GR-15-1033, Findings of Fact, Conclusions, and Order at 32 (May 1, 2017), and *In the Matter of the Application of*

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[719] Minn. Stat. § 216B.16, subd. 4.
[720] Ex. 72 at 25 (Oehlerking-Boes Direct), Ex. 73 at 7 (Oehlerking-Boes Rebuttal).
[721] Ex. 72 at 25 (Oehlerking-Boes Direct), Ex. 73 at 7 (Oehlerking-Boes Rebuttal).
[722] Ex. 72 at 26 (Oehlerking-Boes Direct).
[723] Ex. 44 at 59 (Skelton Direct).
[724] Ex. 626 at 11 (La Plante Direct).
[725] *Id.* The Department subsequently agreed to the *amount* of the costs. *See* Ex. 627 at 3-4, 18 (La Plante Surrebuttal); Ex. 632 at 21, DVL-S-7 (Lusti Surrebuttal).

Northern States Power Company, d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota, MPUC Docket No. E002/GR-12-961.

Analysis

The Department is correct the while the legislature has authorized the PUC to permit recovery of chemical and reagent costs in a FCA rider, the PUC has not yet done so. The PUC has not promulgated any rules for doing so.[726] It maintains that:

> [A]llowing recovery of all reagent costs through the fuel clause, without the careful review of costs as would occur in a rate case, would not be reasonable, and would likely reduce [Applicant's] incentive for efficiency and cost minimization.[727]

Given the lack of a promulgated rule to implement a review of chemical and reagent costs in under a FCA rider, and given the PUC's concern about appropriate incentives for utilities, it cannot be concluded that Applicant has met its burden to demonstrate that including its chemical and reagent costs under its FCA rider is just and reasonable.

Conclusion

Applicant's request to include chemical and reagent costs under its FCA rider should be denied. Applicant should be required to recalculate the test year average, in part, without these costs included.

e. Business Interruption Insurance

Positions of the Parties

Applicant requests that premiums for business interruption insurance and the proceeds from any insurance claims be included in the FCA rider.[728] Applicant is proposing to include business interruption insurance in the fuel clause so both premiums, and any later proceeds, are accounted for symmetrically.[729] Applicant argues that this will ensure customers who pay for the insurance will receive the benefit of the insurance.[730] According to Applicant, the insurance is intended to shield customers from the added costs spot market pricing for replacement power and lost production tax credits in the event its Bison generating assets or the DC Line are offline due to an insured event.[731]

[726] *See* Minn. R. 7825.2390-.2920 (2017).
[727] *In re Application of Otter Tail Power Co. for Auth. To Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E017/GR-15-1033, Findings of Fact, Conclusions, and Order at 32 (May 1, 2017).
[728] Ex. 72 at 27 (Oehlerking-Boes Direct).
[729] *Id.* at 28.
[730] Ex. 73 at 13 (Oehlerking-Boes Rebuttal).
[731] Ex. 72 at 26 (Oehlerking-Boes Direct).

For the same reasons it argues chemical and reagent costs should not be recovered through the FCA rider (improper incentivization), the Department does not agree that the cost of business interruption insurance should be recovered through the FCA rider.[732] Further, argues the Department, Minn. Stat. § 216B.16, subd. 7 does not identify business interruption insurance as a fuel cost the Commission may permit a utility to recover via the FCA rider.[733] This cost should be recovered through base rates, according to the Department.[734]

Analysis

The Department is correct that Minn. Stat. § 216B.16, subd 7 does not include or anticipate business interruption insurance as a recoverable cost under a FCA rider. The costs the PUC are authorized to permit are:

1. federally regulated wholesale rates for energy delivered through interstate facilities;

2. direct costs for natural gas delivered;

3. costs for fuel used in generation of electricity or the manufacture of gas; or

4. prudent costs incurred by a public utility for sorbents, reagents, or chemicals used to control emissions from an electric generation facility, provided that these costs are not recovered elsewhere in rates.[735]

The PUC has not attempted to include costs outside of this brief list in its rules for the automatic adjustment of charges.[736] Thus, there is no legal basis to permit Applicant to recover the cost of business interruption insurance through the FCA rider.

Conclusion

Applicant's request to recover the cost of business interruption insurance through its FCA rider should be denied. Applicant should be required to recalculate the test year average, in part, without this cost.

[732] Ex. 626 at 14 (La Plante Direct).
[733] *Id.*
[734] *Id.*
[735] Minn. Stat. § 216B.16, subd. 7.
[736] *See* Minn. R. 7825.2390-.2920.

f. Nitrous Oxide (NO_x) Allowance

Positions of the Parties

Applicant requests authorization to account for NO_x emission allowances through the FCA rider.[737] According to Applicant, in 2008 the PUC permitted it to account its SO_2 allowances though the FCA rider.[738] This was done to ensure ratepayers received the benefit of revenues Applicant obtained from the sale of its SO_2 allowances.[739] Applicant argues that this same rationale applies to its request to account for NO_x emission allowances.[740] Applicant argues that it wants to be able to return the value of any sold NO_x emission allowances to customers and has no way to do so.[741] Applicant argues that the "emission allowances relate directly to the fuel and purchased energy accounted for in the Company's fuel clause adjustment" and so is reasonable, supported by the evidence, and in the interest of customers.[742] Applicant has only sold NO_x allowances once, in 2015, for $105,000. It does not anticipate any NO_x allowance sales or purchases in the future.[743]

Just like with chemical and reagent costs, and business interruption insurance costs, the Department argues that because NO_x (and SO_2) allowances are not fuel costs, they do not belong in the fuel clause.[744] The Department disagrees with Applicant's characterization of the determinations in Docket No. E-015/GR-08-415.[745] The Department argues that PUC orders "express a reluctance to extend fuel clause treatment to non-fuel items.[746] Finally, the Department argues that the PUC recently addressed the very question of SO_2 and NO_x allowances being included in fuel clauses and determined they would not be.[747]

Analysis

Minn. Stat. § 216B.16, subd. 7(3) permits the "costs for fuel used in generation of electricity" to be included in the FCA rider.[748] Minn. R. 7829.2400 provides definitions to the "cost of fuel consumed in the generation of electricity" and "cost of fossil fuel."[749] These definitions do not reference, or in any way allude, to extraneous costs associated with the burning of fuels, such as emissions. In fact, taken to the extreme, Applicant's argument could result in nearly all of its costs being subsumed into the FCA rider. The

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737 Ex. 72 at 28 (Oehlerking-Boes Direct).
738 *In re Application of Minn. Power for Auth. to Increase Elec. Serv. Rates in Minn.*, MPUC Docket No. E-015/GR-08-415, Order After Reconsideration at 3 (Aug. 10, 2009).
739 *In re Application of Minn. Power for Auth. to Increase Elec. Serv. Rates in Minn.*, MPUC Docket No. E-015/GR-08-415, Findings of Fact, Conclusions of Law, and Order at 61 (May 4, 2009).
740 Applicant Initial Br. at 99 (Sept. 12, 2017) (eDocket No. 20179-135459-02).
741 *Id.*
742 *Id.*; Ex. 72 at 29 (Oehlerking-Boes Direct).
743 Ex. 72 at 29 (Oehlerking-Boes Direct).
744 Ex. 626 at 17 (La Plante Direct).
745 Department Initial Br. at 64 (Sept. 12, 2017) (eDocket No. 20179-135469-01).
746 *Id.* at 65.
747 Ex. 626 at 18 (La Plante Direct); Ex. 627 at 16 (La Plante Surrebuttal).
748 Minn. Stat. § 216B.16, subd. 7.
749 Minn. R. 7825.2400, subds. 8, 9 (2017).

transportation of the fuel, the processing of the fuel, the disposal of the fuel, the plant in which the fuel is burned, the cost of the employees operating the plant, even the electricity produced as a result of the steam created by the burning of the fuel and its transmission and distribution system, are likewise related to the burning of the fuel. Under Applicant's argument, the cost of all those things could be part of the FCA rider. Clearly, this is not the intent of the legislature, which now has included four distinct costs under the automatic adjustment provision of Minn. Stat. § 216B.16, subd. 7.

Applicant's strongest argument is the current inclusion of its SO_2 allowances in the FCA rider. Neither the Administrative Law Judge nor the PUC in Docket No. E-015/GR-08-415 provided a legal basis for inclusion of those allowances in the fuel clause. In fact, Applicant had sought to include future revenues and expenses associated with its SO_2 and NO_x allowances through a single, newly-proposed rider.[750] The PUC authorized Applicant to return revenues from the sale of SO_2 allowances and collect expenses from the purchase of SO_2 allowances through the fuel and purchase power adjustment rider without any explanation for the use of that particular rider.[751] None of the parties in the 2008 rate case explained or even argued for the use of the fuel clause rider and the law at that time, like now, did not permit it.

Conclusion

The FCA rider is not appropriate for Applicant's NO_x revenues and expenses because Minn. Stat. § 216B.16, subd. 7 and Minn. R. ch. 7825 (2017)do not permit inclusion of emissions allowance revenues or costs in FCA riders. Thus, the request for a NO_x allowance in the FCA rider should be denied. Applicant should be required to recalculate the test year average, in part, without the inclusion of a NO_x rider.[752]

xvii. Generation O&M: Supervision and Engineering Expenses and Meter Reading Expenses

Positions of the Parties

Applicant's test year O&M budget included $1,138,982 (total company) for meter reading expenses and $21,404,691 (total company) for generation supervision and engineering expenses. The test year budget is based on input from all 80 "responsibility centers" within the utility, each of which has expertise in its specific area.[753] The generation responsibility centers are each of the specific generation facilities.[754] There are more than 28 FERC accounts that comprise generation O&M expenses.[755] While specific expenses may be budgeted based on specific FERC accounts within a

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[750] *In re Minn. Power for Auth. to Increase Elec. Serv. Rates in Minn.*, MPUC Docket No. E-015/GR-08-415, Findings of Fact, Conclusions of Law, and Order at 60 (May 4, 2009).
[751] *In re Application of Minn. Power for Auth. to Increase Elec. Serv.Rates in Minn.,* MPUC Docket No. E-015/GR-08-415, Order After Reconsideration at 3 (Aug. 10, 2009).
[752] The Administrative Law Judge makes no recommendation regarding the previous order by the PUC on SO_2.
[753] Ex. 53 at 2-4 (Morris Direct).
[754] *Id.* at 2-3.
[755] Ex. 46, JJS-5 at 1 (Skelton Rebuttal).

responsibility center, the actual cost may be charged to a different account within the responsibility center.[756] Thus, care must be taken when comparing budgets and expense reports.[757]

Applicant's budgeting for O&M expenses changed from the 2012-16 period to the test year.[758] Cost controls, changes to generating units resulting in significant salary, wage, and benefit differences, and refocusing efforts from capital projects to O&M all contributed to these changes.[759]

The Department argues that Applicant's generation O&M test year budget is not reasonable because the numbers Applicant used are not supported by evidence.[760] According to the Department, for Applicant to meet its burden of proving its test year O&M expenses are just and reasonable Applicant must provide "the level of information that would allow for an independent reproduction of [Applicant's] computations of the 2017 Test Year Budget amounts . . ."[761]

The Department argues the test year generation O&M budget could have reasonably been based on actual 2016 expense levels, but maintains that the better practice would be to use of a five-year average.[762] The Department argues that the level of expenses Applicant proposes to charge in rates far exceeds its actual historical expenses in each year of the past five years.[763]

The Department specifically addresses meter reading expenses (FERC Account No. 902). According to the Department, Applicant did not base its budget for these expenses on a quantitative analysis.[764] Thus, the Department was not able to determine the basis for and reasonableness of the requested recovery amount.[765] The Department claims the budgeted amount for meter reading expenses is an increase of 251 percent.[766] The Department argues that Applicant's claim that a more "holistic" view of the meter reading activities and expenses should be taken is insufficient to meet Applicant's burden of proof because Applicant has specific knowledge about how its operations work and failed to provide the information through the hearing process.[767] The Department further argues that Applicant's information about the meter reading budgets from the response centers does not support its test year request.[768] The records provided, according to the Department, demonstrate that some responsibility centers systematically over-budget

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[756] *Id.* at 2.
[757] *Id.* at 9-10; Ex. 50 at 14 (Fleege Rebuttal).
[758] Ex. 46 at 9, 12-15 (Skelton Rebutal).
[759] *Id.* at 12; Ex. 58 at 4 (Johnson Rebuttal).
[760] Ex. 625 at 14 (Ouanes Surrebuttal).
[761] *Id.* at 14-15.
[762] Ex. 624 at 34 (Ouanes Direct); Ex. 625 at 14 (Ouanes Surrebuttal).
[763] Ex. 625 at 14 (Ouanes Surrebuttal).
[764] Ex. 624 at 32 (Ouanes Direct).
[765] *Id.*
[766] *Id.*
[767] Ex. 625 at 16-18 (Ouanes Surrebuttal).
[768] *Id.* at 18-19.

meter reading expenses.[769] The Department also argues that comparison of the test year meter reading budget with previous spending is irrelevant to what Applicant should recover in the test year.[770] The Department claims that Applicant never, in response to discovery requests related to meter reading expenses, indicated that meter expenses (FERC Account No. 586) also be examined.[771] As a result, the Department argues that the test year recovery for meter reading expenses be set at $488,376 and not the requested $1,138,982.

The Department also argues that Applicant did not adequately support its proposed increase of 89 percent for generation supervision and engineering costs.[772] A portion of these expenses are recorded in FERC Account Nos. 535 and 546, according to the Department.[773] Applicant again only provided a high-level description of its budgeting process, not a quantitative analysis to develop its proposal for these expenses.[774] The Department argues that the evidence shows Applicant's 2016 generation supervision and engineering budget of $20.9 million was 84 percent higher than the actual spend amount of $11.3 million, and there was a downward trend in spending over the last five years.[775] Thus, to be conservative, the Department argues for the use of the average of the last five years actual amount, $14,126,033 (instead of the proposed $21,404,691).[776] This includes the following adjustments:

- decrease steam O&M supervision expense by $2,708,635;
- decrease hydro O&M supervision expense by $1,103,443; and
- decrease other power O&M supervision by $2,328,247.[777]

Analysis

Applicant's approach to budgeting for its generation O&M for the test year, while perhaps not a perfect approach, results in a request for recovery of expenses that is just and reasonable. There is no specific approach to budgeting required by law. To determine whether Applicant's budget is just and reasonable requires a determination about "whether the ratepayers or shareholders should bear those costs."[778] The standard of proof, a preponderance of the evidence, requires the tribunal to consider "whether the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility considered together with the Commission's statutory responsibility to enforce the state's public policy that retail customers of utility services shall be furnished such services at reasonable rates."[779] In the evaluation of "disputes in the typical rate case, the accent is more on the inferences and conclusions to be drawn from the basic facts (i.e., amount of

[769] *Id.* at 17-18.
[770] *Id.* at 20.
[771] Ex. 624 at SO-14 (Ouanes Direct); Evidentiary Hearing Tr. Vol. 4 at 77 (Ouanes).
[772] Ex. 624 at 32 (Ouanes Direct).
[773] *Id.,* SO-12, SO-13.
[774] *Id.* at 32.
[775] *Id.* at 31-33.
[776] *Id.* at 34-35.
[777] Ex. 632 at 24-25 (Lusti Surrebuttal).
[778] *Pet. of N. States Power Co.*, 416 N.W.2d 719, 722-23 (Minn. 1987).
[779] *In re Minn. Power & Light Co.*, 435 N.W.2d 550, 554 (Minn. Ct. App. 1989).

claimed costs) rather than on the reliability of the facts themselves."[780] "Any doubt as to reasonableness should be resolved in favor of the consumer."[781]

The Department argues that Applicant has been evasive or incomplete in its presentation of facts, and that its approach to budgeting for the test year is superior. However, the Department's arguments are not persuasive with regard to Applicant's generation O&M budgeting. It is not a question of which approach, Applicant's or the Department's, is superior. Rather, it is simply a question of whether Applicant's proposed test year budget is necessary and reasonable to provide electric service to customers at reasonable rates. The Administrative Law Judge concludes that Applicant has met its burden.

The Department's argument that it could not independently reproduce the numbers Applicant arrived at does not mean Applicant's numbers are unreasonable. The Department simply approached the budgeting question from a different perspective than Applicant. The Applicant used a "holistic" approach that considered all of the quirks in its business practices, as well as the changes it is making in its operations.[782] The Department, on the other hand, used a much more mechanical approach in an effort to run clear and clean calculations based on spreadsheets of numbers. Neither side is wrong in its approach. In this case, Applicant's justifications and explanations for its generation O&M budget for the test year is rational. That is, it is supported by its explanations for how it is planning to use the money it seeks to recover from ratepayers in the test year to deliver them safe, reliable electric service.

Conclusion

Applicant's proposed budget for generation O&M supervision and engineering and meter reading in the test year is just and reasonable. Applicant should be permitted to include the claimed amount in the test year average.

xviii. Sales Forecasts - Keetac[783]

Positions of the Parties

Applicant's sales forecast for the 2017 test year were challenged by OAG, LPI, and the Department. Those parties believe Applicant's forecast is too low, which will result in excessive rates. Following review of additional information, the Department determined that Applicant's sales forecast was reasonable. LPI and OAG continue to challenge

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[780] *Id.*

[781] Minn. Stat. § 216B.03.

[782] To the extent Applicant has "quirks," such as expenses budgeted for in one account, but the actual spending accounted for in a different account, it would not be an extreme demand of the PUC to require proper and consistent accounting. Proper and consistent accounting would greatly impact the efficiency of the rate-making process plus improve the efficiency of Applicant's business, benefitting both ratepayers and shareholders.

[783] On October 25, 2017, Applicant notified the PUC that UPM Blandin Paper Machine 5 would be permanently closing by the end of the first quarter in 2018, and Applicant does not know the impact of the closure on sales.

Applicant's sales forecast based on its forecast for one taconite operation: renewed production at the Keetac mine and taconite facility in Keewatin, Minnesota.

Applicant's sales forecast for retail electric service is for 9,212,383 MWh in the test year.[784] As of June 2017, the actual sales were 3.5 percent below the forecasted amount.[785]

The forecast had been updated in February 2017 because of the restart of the Keetac facility, which was to be operational in March 2017.[786] The revised forecast was based on nine months of sales to U.S. Steel for the Keetac in 2017, as opposed to none.[787] This represents about a 4.5 million ton increase in taconite production, or 37 million tons total for the six mines Applicant serves.[788] The total capacity of the six mines is 41 million tons annually.[789] Thus, Applicant's sales forecast is updated to reflect electric sales for 90 percent utilization of the capacity of the six mines Applicant serves.[790]

Applicant further supports its position with evidence about current trends in the steel industry. Applicant argues that domestic steel production is currently operating at a lower capacity than it was prior to the 2008/2009 downturn.[791] Applicant argues that the employment of different technology to produce steel is shifting away from taconite because steel producers are moving away from blast furnaces suitable for taconite to electric arc furnaces which are not.[792] Applicant also argues that steel imports have not significantly declined, despite federal protective measures, and so production and prices for the steel Minnesota taconite produces remains depressed.[793]

OAG argues that Applicant has incentive to under-estimate its sales forecast because if actual sales outpace the sales forecasted during the test year, the company shareholders will benefit.[794] OAG and LPI argue that a representative test year must be determined based on 12 months of full utilization of production at the Keetac facility rather than just nine months.[795] They argue that Keetac is likely to remain at full production for the foreseeable future.[796] OAG also argues that iron and steel industries are strong, that federal initiatives to protect United States Steel producers will help, and that Applicant has indicated it agrees with this through its own evidence: testimony of Perala, Ex. 64 at

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[784] Ex. 69 at 5, MAP-SD-33 (Pierce Supplemental Direct).
[785] Ex. 71 at 3-4 (Pierce Rebuttal).
[786] Ex. 64 at 4 (Perala Second Supplemental Direct).
[787] *Id.*
[788] *Id.* at 5.
[789] *Id.*
[790] *Id.*
[791] *Id.* at 8-9.
[792] *Id.* at 9-10.
[793] *Id.* at 10-11.
[794] OAG Initial Br. at 54-55 (Sept. 12, 2017) (eDocket No. 20179-135457-02).
[795] Ex. 100 at 5 (Gorman Direct). OAG's argument is based on evidence provided by LPI and Department witnesses. The Department's position has changed, however. This is not acknowledged by OAG in its brief.
[796] Ex. 64 (Perala Second Supplemental Direct).

4, the Chief Executive Officer's communications with investors, and comments from the Chief Executive Officers of U.S. Steel and Cliffs Resources.[797]

Analysis

Applicant's reliance on a test year sales forecast that is based on 90 percent utilization of taconite production facilities is reasonable. First, while OAG argues that Applicant has incentive to understate its sales forecast, it has not provided evidence of this motivation. To the extent it has provided evidence of what the sales forecast should be, OAG and LPI have not overcome the preponderance of evidence provided by Applicant.

The focus and arguments about whether the revitalized production at Keetac should be based on nine or 12 months misses the point. Applicant validly relies on the nine-month of production in 2017 at Keetac not for the sake of forecasting Keetac production, but for forecasting the total production of all of Applicant's taconite producing customers. The most recent ten-year average for these customers is 89 percent utilization. Applicant is forecasting 90 percent. This is based, in part, on Keetac's production for nine months in 2017, but not solely on that fact. Because of the volatility of the taconite and steel industries, Applicant wisely used the nine month consideration as a proxy for computing averages for each individual taconite producer.

Conclusion

Applicant has demonstrated, by a preponderance of the evidence, that its sales forecast for the test year is reasonable. Thus, it is recommended its forecast in sales for the test year be accepted into the rate base.

xix. Taconite Harbor Re-Start/Re-Idle

Positions of the Parties

The PUC approved Applicant's plan to idle Taconite Harbor Energy Center (THEC) units 1 and 2 in the fall of 2016 on July 18, 2016.[798] Applicant anticipates the units will be restarted at least once per year between 2017 and 2020 (four years), at $1.25 million per event, for system reliability reasons and for providing power into the MISO capacity auction each year.[799] There could be additional restarts and correspondingly higher costs.[800]

OAG argues that because there are only two scheduled start-up and re-idle events between 2017 and 2020, the test year should only include one third of the $1.25 million

[797] Ex. 501 at 46-47 (Lebens Amended Direct); Ex. 515 at 2 (Allete Earnings Call Aug. 2, 2017).
[798] Ex. 44 at 20 (Skelton Direct); *In re Minn. Power's 2016-2030 Integrated Res. Plan*, MPUC Docket No. E015/RP-15-690, Order Approving Resource Plan with Modifications at 5 (July 18, 2016).
[799] Ex. 48 at 3-4 (Skelton Surrebuttal); *In re Minn. Power's 2016-2030 Integrated Res. Plan*, MPUC Docket No. E015/RP-15-690, Order Approving Resource Plan with Modifications at 5 (July 18, 2016).
[800] Ex. 48 at 4 (Skelton Surrebuttal).

sum; or approximately $416,666.[801] If the units are not re-started every year, according to the Department, Applicant will over-recover its costs.[802]

Analysis

Applicant has demonstrated, by a preponderance of the evidence, that it will likely incur at least $1.25 million in costs to re-start and re-idle THEC units 1 and 2 in each of the next four years, including the test year. These events are necessary for MISO accreditation and for system reliability. In addition, the units may be called upon for the MISO capacity auction, which will result in energy sales that will benefit both ratepayers and shareholders.

Conclusion

Given it is more likely than not that the THEC units 1 and 2 will be re-started and re-idled at least one per year between 2017 and 2020, Applicant's request to include $1.25 million for the costs of one re-start and re-idle in the test year is just and reasonable. It is recommended that Applicant be permitted to keep this cost in the test year average.

xx. Solar Energy Standard (SES) Capacity Benefits

Positions of the Parties

The Camp Ripley Solar Project is a 10MW solar facility constructed at Camp Ripley, a Minnesota Army National Guard base near Little Falls, Minnesota, which was dedicated in 2017. In Applicant's Camp Ripley Solar Project Petition (a different matter), Applicant proposed a methodology for allocating costs between solar-paying customers and customers exempt from the Solar Energy Standard (SES) under Minn. Stat. § 216B.1691, subd. 2f(e).[803] The PUC directed Applicant to develop and provide in this rate proceeding a methodology for allocating Camp Ripley's solar capacity benefits between SES-exempt and solar-paying customers.[804]

In the current proceeding, Applicant proposes to calculate the value of solar capacity based on the clearing price for capacity in MISO's annual Planning Resource Auction in Local Resource Zone 1.[805] Further, Applicant proposed to base the MW value used to calculate the solar capacity on the MISO Zonal Resource Credits (ZRC) assigned to Camp Ripley or future SES solar projects through the MISO Resource Adequacy Program.[806] Each month the total SES capacity value will be based on the solar ZRCs

[801] *Id.* at 2; Ex. 507 at 4 (Lee Rebuttal).
[802] Ex. 507 at 4-5 (Lee Rebuttal).
[803] Ex. 67 at 41 (Pierce Direct).
[804] *In re Pet. of Minn. Power for Approval of Investments and Expenditures in the Camp Ripley Solar Project for Recovery Through Minn. Power's Renewable Res. Rider Under Minn. Stat. 216B.1645 and Related Tariff Modifications*, MPUC Docket No. E015/M-15-773, Order Limiting Cost Recovery, Approving Fuel and Purchased Energy Adjustment Rider Revisions, and Approving Proposed Solar Energy Adjustment Rider (Dec. 12, 2016).
[805] Ex. 67 at 42 (Pierce Direct).
[806] *Id.* at 42.

multiplied by the most recent clearing price from the MISO Planning Resource Auction for capacity in Local Resource Zone 1.[807]

Once the value of the benefits is established, Applicant must then allocate those benefits between customers who are solar-paying and those who are SES-exempt. Applicant proposes to do this by collecting the value of the solar capacity through Applicant's Renewable Resources Rider and then crediting that amount to all solar-paying customers through Applicant's Solar-Renewable Resources Factor.[808]

CEO argues that Applicant's proposal should be rejected because it significantly undervalues the solar capacity and is inconsistent with how Applicant values the capacity from any of the other generation resources that it owns. According to CEO, Applicant admitted that "it is not the Company's position that the capacity value for all of its generation resources that provide capacity in MISO Local Resource Zone 1 is limited to the 'lost opportunity to sell excess capacity into the MISO market through the annual Planning Resource Auction.'"[809] Stated another way, the value of capacity to meet resource adequacy requirements is not measured by the value of a unit of excess capacity sold into the Planning Resource Auction.[810] CEO argues that Applicant has not demonstrated that this is the appropriate measure.[811]

According to CEO, a preferable method would be to use the avoided capacity calculation in Minnesota Rules 7835.0600 (2017).[812] Minnesota Rule 7835.0300 requires a utility to reprot avoided capacity values based on its current capacity contracts and avoided costs, which are used in setting distributed generation compensation rates, according to Applicant.[813] Minnesota Rule 7835.0600 (Schedule B) explains how the utility is to calculate these values.[814]

CEO argues the capacity value that would be reported pursuant to Minn. R. 7835.0300 (2017) is preferable to Applicant's proposal.[815] It is a required annual filing and therefore will be automatically updated and available to be used in accrediting SES customers with the value of solar capacity as solar resources are added to Applicant's system.[816] CEO also argues this avoided capacity value is "based on Minnesota Power's *actual* contract pricing" and, thus, reflects real-world costs and benefits that are more likely to result in fair and reasonable rates.[817]

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[807] *Id.* at 42-43.
[808] *Id.* at 43.
[809] Ex. 252 at 5, AG-1 (Gleckner Direct).
[810] CEO Initial Br. at 16 (Sept. 12, 2017) (eDocket No. 20179-135454-01).
[811] *Id.*
[812] *Id.*
[813] *Id.*
[814] *Id.*
[815] *Id.* at 17.
[816] Ex. 252 at 8-9 (Gleckner Direct).
[817] *Id.* at 8.

The Department agrees with CEO's proposal to calculate SES capacity benefits as the avoided capacity costs from Applicant's qualifying facility tariff.[818] According to the Department, this proposal is superior to Applicant's proposal to calculate SES capacity benefits as the market value of solar in MISO's Planning Resource Auction because it correctly reflects the avoided capacity costs due to SES solar.[819] Applicant's proposal, in contrast, does not incorporate avoided costs.[820] OAG also found CEO's proposal "the most reasonable because it promotes consistency in valuing distributed resources and appears to be less administratively burdensome."[821]

Analysis

On December 12, 2016, the PUC accepted Applicant's "commitment…to develop and provide in its 2016 rate case a methodology for allocating the Camp Ripley solar capacity benefits between SES-exempt and non-exempt, solar-paying customers."[822] The PUC had determined that the Camp Ripley solar project would provide capacity benefits that "will flow to all customers regardless of whether they help pay for the project."[823]

Applicant's proposed method for allocating the capacity benefits (costs of facilities used to generate, transmit, and distribute electricity and the fixed operating and maintenance costs of these facilities which are not incurred as a result of the solar project) is based on first, determining the value of the benefits. This is where the dispute on this sub-issue lies. There is no dispute about the methodology for allocation of the capacity benefits themselves. The allocation is based on the method used in MPUC Docket No. E-015/M-15-773 (providing solar-paying customers a credit through the Fuel and Purchased Energy Adjustment Rider because that rider collects revenue from all customers).

To determine whether Applicant's proposal to determine value of the capacity benefits requires a preponderance of the evidence showing "the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility considered together with the Commission's statutory responsibility to enforce the state's public policy that retail customers of utility services shall be furnished such services at reasonable rates."[824] In the evaluation of "disputes in the typical rate case, the accent is more on the inferences and conclusions to be drawn from the basic facts (i.e., amount of claimed costs) rather

[818] Ex. 612 at 40 (Collins Surrebuttal).
[819] *Id.*
[820] *Id.*
[821] Ex. 511 at 38 (Nelson Rebuttal).
[822] *In re Pet. of Minn. Power for Approval of Investments and Expenditures in the Camp Ripley Solar Project for Recovery Through Minn. Power's Renewable Res. Rider Under Minn. Stat. 216B.1645 and Related Tariff Modifications*, MPUC Docket No. E015/M-15-773, Order Limiting Cost Recovery, Approving Fuel and Purchased Energy Adjustment Rider Revisions, and Approving Proposed Solar Energy Adjustment Rider at 7 (Dec. 12, 2016).
[823] *Id.* at 6.
[824] *In re Minn. Power & Light Co.*, 435 N.W.2d 550, 554 (Minn. Ct. App. 1989).

than on the reliability of the facts themselves."[825] "Any doubt as to reasonableness should be resolved in favor of the consumer."[826]

Applicant's proposal, while perhaps not the most desired by all the parties, is reasonable. The law does not require it to be optimum. CEO's plan appears to be more just and reasonable because it is based on requirements already in place under Minn. R. 7835.0300. Applicant's argument that using the calculation under Minn. R. 7835.0600 (2017) is not appropriate because of the provision in subpart 3 requiring "a description of all planned firm capacity purchases…during the next ten years" when the solar facility does not provide "firm power" is unavailing. Subpart 3 is simply a part of the whole. If there are no "firm capacity purchases" to be accounted for, then this factor would not be addressed in the calculation in Schedule B under the rule. Nevertheless, Applicant has presented a methodology for allocating the capacity benefits. Even though it is different from the one argued for by other parties, and even assuming the opposing method is better, the law only requires Applicant's approach to be just and reasonable in light of its responsibility to provide electric service at reasonable rates. Applicant's proposal to base the value of the Camp Ripley solar project's capacity benefits on the MISO Planning Resource Auction is a reasonable approach to ensure electric service at reasonable rates.

Conclusion

Applicant's proposed method of calculating the value of solar capacity based on the clearing price for capacity in MISO's annual Planning Resources Auction in Local Resource Zone 1 is just and reasonable. The PUC should adopt Applicant's overall proposed method for allocating capacity benefits from the Camp Ripley plant, and permit Applicant to use this value in calculating the test year average.

D. Conclusion

Based on all of the conclusions under this issue, the test year revenue increase sought by Applicant is not reasonable and will result in unreasonable and excessive capital earnings. The average rate base of the 2017 test year should be recalculated by Applicant based on the findings, conclusions, and recommendations herein, which impact the operating income and gross revenue deficiency calculations previously provided.

III. PROPOSED CAPITAL STRUCTURE AND RETURN ON EQUITY

A. Legal Standard

Applicant bears the burden of proving, by a preponderance of the evidence, that its proposed ROI, which results from its proposed ROE and capital structure, is fair and reasonable.[827] The ROI "should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical

[825] *Id.*
[826] Minn. Stat. § 216B.03.
[827] Minn. Stat. § 216B.16, subds. 4, 6.

management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties."[828] "The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."[829] "That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital."[830]

B. Applicant's Proposal

Applicant proposes a capital structure comprised of 46.19 percent long-term debt and 53.81 percent common equity.[831] Applicant does not carry short-term debt in order to ensure that it has the capacity to obtain necessary financing in the event one or more of its industrial customers discontinues or sharply reduces its operations.[832]

Applicant's proposed cost of debt is 4.517 percent and the proposed return on equity (ROE) is 10.15 percent.[833] The ROE range calculated by Applicant is 9.8 to 10.3 percent.[834] The weighted return on investment (ROI) would be 7.54 percent.

Applicant's proposal is based on "a quantitative analysis that included the consideration of" different models, and their variants, plus the effect of flotation costs.[835] Applicant relies on five key factors to support its position on its proposed capital structure and rate of return: relative risk, ROE, common equity ratio, nature and cost of debt, and impact to credit metrics of alternative outcomes. Based on this combination of multiple analytical models and subjective assessments, Applicant devised a proposed return on equity of 10.15 percent.

In utilizing the analytical models, Applicant's expert witness, Robert Hevert, utilized the Constant Growth Discounted Cash Flow (DCF) model, the Two-Growth DCF model, the Capital Asset Pricing Model (CAPM), and the Bond Yield Plus Risk Premium (BYPRP) approach.[836] Hevert believes the DCF model variants produce results that are unreliable when considered in context of observable and important market indices, such as utility sector Price/Earnings ratios and falling dividend yields.[837] Hevert believes the Risk Premium models are more reliable than the DCF models because they directly reflect measures of capital market risk.[838]

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[828] *Bluefield Waterworks & Imp. Co. v. Public Service Commission*, 262 U.S. 679, 693 (1923).
[829] *Federal Power Comm. V. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).
[830] *Id.*
[831] Ex. 37 at 29 (Cutshall Direct).
[832] Ex. 38 at 20 (Cutshall Rebuttal).
[833] Ex. 27 at 2 (Cutshall Direct); Ex. 35 at 3 (Hevert Rebuttal); Ex. 601 at 42 (Amit Direct).
[834] Ex. 34 at 4 (Hevert Direct).
[835] *Id*.
[836] *Id.* at 4, 24-36. The CAPM and BYPRP are both "Risk Premium" models.
[837] *Id.* at 4-6, 29.
[838] *Id.* at 33, 36.

C. Challenges to Proposal

The Department, OAG, LPI, and Wal-Mart all take issue with one or more components of Applicant's proposal. OAG believes its proposed ROE is the most reasonable. Which party presents the best proposal is not the standard by which the PUC is to judge Applicant's proposal. Rather, the standard is whether Applicant's proposed ROE is fair and reasonable.[839]

LPI argues that Applicant's capital structure is unreasonable because it is "far more expensive than needed to maintain [Applicant's] financial integrity and provide access to capital."[840] LPI argues the cost of the proposed capital structure will put its members at a competitive disadvantage.[841] According to LPI, a reasonable common equity ratio would be 51 percent to 49 percent long-term debt ratio.[842] This would be consistent with other companies similar to Applicant, according to LPI.[843] LPI further argues that its analysis of Applicant's capital structure is more focused than Applicant's own analysis.[844] Applicant incorporates ALLETE's entire business into its analysis which, LPI argues, renders the analysis flawed.[845]

The Department argues that the DCF analysis Applicant used is not reasonable because it screened out large-cap companies.[846] The Department also argues that using 90 and 180 day stock prices in the DCF models is not reasonable because longer-term historical prices may result in biased dividend yields that reflect out-of-date information.[847]

The Department and OAG challenge how Applicant accounts for risk and this is related to Applicant's selection of a proxy group. The Department asserts that Applicant's elimination of companies from its proxy group that have a ROE less than 8 percent is not reasonable. There are four reasons behind this objection. First, according to the Department, current market conditions require a low-end cut off of 7 percent if such a screen is used.[848] Second, the risk premium differential between an 8 percent ROE and the yield on 20-year treasury bonds is only 5.46 percent, compared to Dr. Amit's average CAPM risk premium of 6.35 percent.[849] This is a much less significant difference than a prior case (2013 Xcel) where Dr. Amit used an 8 percent low-end screen.[850] Third, using a Two-Growth DCF model accounts for outlier companies because it reflects all of their

[839] Minn. Stat. § 216B.16, subd. 6.
[840] LPI Initial Br. at 13 (Sept. 12, 2017) (eDocket No. 20179-135470-02); Ex. 114 at 18 (Walters Surrebuttal).
[841] LPI Initial Br. at 13 (Sept. 12, 2017) (eDocket No. 20179-135470-02).
[842] *Id.* at 14, 16; Ex. 103 at 21 (Walters Direct).
[843] LPI Initial Brief at 14 (Sept. 12, 2017) (eDocket No. 20179-135470-02); Ex. 103 at 28 (Walters Direct).
[844] LPI Initial Brief at 14-15 (Sept. 12, 2017) (eDocket No. 20179-135470-02); Ex. 103 at 60 (Walters Direct); Ex. 114 at 20 (Walters Surrebuttal).
[845] LPI Initial Brief at 15 (Sept. 12, 2017) (eDocket No. 20179-135470-02); Evidentiary Hearing Tr. Vol. 3 at 93-94 (Walters).
[846] Ex. 601 at 45 (Amit Direct).
[847] *Id.* at 47.
[848] Ex. 606 at 16 (Amit Surrebuttal); Evidentiary Hearing Tr. Vol 3 at 236-37 (Amit).
[849] Ex. 606 at 16 (Amit Surrebuttal).
[850] *Id.*

current market data. In this case, none of the proxy companies had a ROE below 8 percent, so the screen would not have eliminated any companies.[851] Finally, if a minimum 8 percent ROE screen is used, a maximum screen, such as 10 percent, should also be used.[852] For all these reasons, the Department argues that an 8 percent cut-off screen is unreasonable.[853]

OAG argues that Applicant is not riskier than its peers based, in part, on the Department's arguments.[854] OAG also argues that Applicant's analysis comparing its risk with that of its peers is flawed because the analysis only focuses on one risk factor, rather than a holistic analysis.[855] According to OAG, Applicant's risk is mitigated by its cost-recovery riders and it has an $80 million stream of low-risk revenue from utility rates.[856] Further, according to OAG, the DCF analysis incorporates broad consideration of specific risk factors through the formation of the proxy group.[857] As a result, and because all risk factors are incorporated into the DCF analysis, the ROE selected should be the midpoint between the results of the two variants, not a number above or below the mean.[858] To deviate from that number, when considering a DCF analysis, would be double-counting, according to OAG.[859]

The Department and OAG challenge Applicant's use of older market data. The Department argues that reliance on ROEs from other public utility commissions is not reasonable because authorized ROEs reflect historical, dated cost of capital and do not reflect the current, expected cost of capital.[860] According to the Department, the ROE must reflect current conditions to avoid setting a rate that is higher than necessary to attract investors. Relying on data from current conditions also ensures the ROE is not too low to attract investors.[861] OAG also argues that Applicant's analysis is also not reasonable because it relies on outdated market data.[862] OAG believes the analysis should be conducted with data collected over 30 trading days, not 90 or 180, as used by Applicant.[863] A core assumption of financial analysis is that markets are efficient and reflect all publicly available information.[864] OAG argues that Applicant's data is older and therefore not as reliable.[865]

The Department argues Applicant's analysis upon which it generated a CAPM average ROE of 11.37 percent is flawed for several reasons. First, the Department argues

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851 *Id.*
852 *Id.*
853 *Id.* at 17.
854 OAG Initial Br. at 96-97 (Sept. 12, 2017) (eDocket No. 20179-135457-02).
855 Ex. 504 at 21 (Lebens Surrebuttal).
856 *Id.*
857 OAG Initial Br. at 98 (Sept. 12, 2017) (eDocket No. 20179-135457-02).
858 *Id.* at 98-99.
859 *Id.* at 99.
860 Ex. 606 at 10-11 (Amit Surrebuttal).
861 *Id.*
862 Ex. 501 at 13-14 (Lebens Amended Direct).
863 *Id.*
864 *Id.*
865 OAG Initial Br. at 102-03 (Sept. 12, 2017) (eDocket No. 20179-135457-02).

that the use of 30-year treasury bonds is not reasonable and biases the ROE upward.[866] The Department argues that use of 20-year treasury bonds is preferable because they have less interest risk.[867] Applicant's argument that security case duration warranted the use of the 30-year treasury bonds is without merit, according to the Department, because equity life is infinite and the difference between 20 and 30-year treasury bonds on this basis is insignificant with respect to equity life.[868] Further, according to the Department, it is only appropriate to use the current rather than projected yields on treasury bonds because doing so best reflects current investors' expectations, and projected yields on 30-year bonds may not reflect current expectations.[869] The Department also believes companies that do not pay dividends should not be included in the Bloomberg and Value Line market portfolio data used for CAPM analysis.[870] Correcting for these considerations, the Department asserts that the correct CAPM ROE is 9.14 percent.[871]

The Department argues Applicant's Risk Premium analysis is flawed because Hevert's regression analysis assumes that two coefficients are stable over time and do not depend on investors adjusting their expectations.[872] Further, the use of a volatility measure variable or a credit spread risk measure do not address the flaw.[873] Thus, according to the Department, the results of Applicant's Risk Premium ROE analysis should be disregarded.[874]

OAG and LPI argue that the addition of flotation costs to the models is unreasonable. OAG argues that flotation costs should not be included in the ROE because investors understand the concept of flotation costs and have already incorporated it into their expectations, which are then used to inform the DCF analysis.[875] If flotation costs are included, OAG argues that they should be calculated based on an average of the last equity offering, which results in a flotation cost of .0055 percent in this case.[876] According to LPI, Applicant has not demonstrated what its actual flotation costs are.[877] LPI argues that flotation costs should not be approximated because they should be known, measurable, and verifiable in order to show that they are reasonable.[878] Further, according to LPI, the known flotation costs should be included in the cost of service.[879] LPI also argues that because Applicant is not a publicly traded company, and because infusions of equity by its parent company, ALLETE, would not incur flotation costs, it is unreasonable for Applicant to recover such costs.[880] If flotation costs are to be

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[866] Ex. 606 at 18 (Amit Surrebuttal).
[867] *Id.*
[868] *Id.* at 19.
[869] *Id.*
[870] Ex. 601 at 50 (Amit Direct); Ex. 606 at 19-20 (Amit Surrebuttal).
[871] Ex. 606 at 20, 23 (Amit Surrebuttal).
[872] Ex. 601 at 51-52 (Amit Direct).
[873] Ex. 606 at 21 (Amit Surrebuttal).
[874] *Id.* at 20-21, 23.
[875] Ex. 501 at 22-23 (Lebens Amended Direct).
[876] Ex. 504 at 6 (Lebens Surrebuttal).
[877] Ex. 103 at 65 (Walters Direct).
[878] *Id.*
[879] *Id.* at 65-66.
[880] *Id.* at 66.

recovered, LPI argues, the Commission "should have the Company identify its allocated share of the stock issuance and flotation costs should be recovered in cost of service rather than a return on equity adder."[881]

Wal-Mart argues that the ROE employed in other cases in Minnesota and around the country should be used as a "yard-stick" in evaluating the general reasonableness of Applicant's proposed ROE.[882] Wal-Mart believes the PUC should consider the impact of the rate increase on ratepayers when setting the ROE.[883] Wal-Mart asserts that the PUC should consider three risk-reducing measures available to Applicant: 1) Applicant's ability to recover $32 million from the interim revenue increase before the revenue requirement determination; 2) Applicant's use of a future test year, which reduces regulatory lag; and 3) Applicant's proposed ARRM.[884] Finally, Wal-Mart argues that the relatively high concentration of Applicant's industrial load be considered as a risk-factor by the PUC.[885]

D. Analysis

i. Capital Structure

In order to determine a reasonable cost of equity to factor into Applicant's rates, the cost of common equity must be inferred from market data for companies that present similar investment risks.[886] This is because Applicant is a wholly owned subsidiary of ALLETE.[887] To accomplish this, a group of companies similar to Applicant, but with publicly traded common stock, must serve as proxies. Facts about the companies are then put into an analytical model to generate an estimated cost of equity. The selection of the proxies, the factors put into the models, and the models used to conduct the analysis, are all variables that must be considered to determine whether the resulting capital structure and return on equity is fair and reasonable.

Applicant has the burden of proof, by a preponderance of the evidence, to show that its requested rates are just and reasonable.[888] The Minnesota Supreme Court has explained the use of the preponderance of the evidence standard in Minnesota utility rate proceedings.[889] According to the Court, the standard is met when:

> the evidence, even if true, justifies the conclusion sought by the petitioning utility when considered together with the Commission's statutory duty to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates.[890]

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[881] *Id.* at 67.
[882] Ex. 151 at 8-10 (Chriss Direct).
[883] Wal-Mart Initial Br. at 3 (Sept. 12, 2017) (eDocket No. 20179-135455-01).
[884] *Id.*
[885] Ex. 151 at 15 (Chriss Direct).
[886] *In re App. of Minn. Energy Resources Corp. for Auth. to Increase Rates for Natural Gas Serv.in Minn.*, MPUC Docket No. G-011/GR-15-736, Findings of Fact, Conclusions, and Order at 19 (Oct. 31, 2016).
[887] Ex. 32 at 2-3 (McMillan Direct).
[888] Minn. Stat. § 216B.16, subd. 4.
[889] *In re Northern States Power*, 416 N.W. 2d 719 (Minn. 1987).
[890] *Id.* at 722.

In Applicant's last rate case in 2010, the equity ratio was set at 54.29 percent.[891] Here, Applicant's proposed equity ratio is 53.81 percent to 46.19 percent long-term debt. The cost of long-term debt is 4.52 percent. Although it is on high end of the range of reasonable equity ratios, the proposed equity ratio may reasonable. However, flaws in Applicant's analysis, discussed in more detail below, require withholding final judgment on the capital structure.

ii. Return on Equity

The PUC has examined the use of various analytical models for determining the cost of equity over the years, and has developed opinions about the reliability of each model. The PUC has used the CAPM as a secondary, corroborating tool.[892] The PUC has relied on the BYPRP model less heavily because it is "prone to producing volatile and unreliable outcomes."[893] The PUC prefers the DCF model, however, "because its inputs are more objective, its workings more transparent, and its outcomes more replicable than those of other models."[894] As described by the PUC:

> The DCF model uses the current dividend yield and the expected growth rate of dividends to determine what rate of return is high enough to induce investment. The model is derived from a formula used by investors to assess the attractiveness of investment opportunities using three inputs—dividends, market equity prices, and earnings/dividend growth rates. Its two basic variants are the Constant-Growth DCF, the classic version, and the Two-Growth DCF, designed for situations in which the short-term, projected earnings growth rates may not be expected to continue in the long run. The two-growth model uses one growth rate for an initial period, followed by a different growth rate for the long term.[895]

The PUC has rejected using multiple cost-of-equity models to generate a ROE number because:

> It is not the number of models in the record that ensures a sound decision, but the appropriateness of each model for the purpose at hand, the quality of the data selected as inputs, and the caliber of the analysis applied to the results. Using three models does produce a more detailed record, but it also multiplies the risk of inaccurate inputs and increases the number of points at which subjective judgments are required.[896]

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[891] *In re App. of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E-015/GR-09-1151, Findings of Fact, Conclusion and Recommendation at 28 (Aug. 17, 2010).
[892] *In the Matter of the App. of Minn. Energy Resources Corp. for Auth. to Increase Rates for Natural Gas Service in Minn.*, MPUC Docket No. G-011/GR-15-736, Findings of Fact, Conclusions, and Order at 20.
[893] *Id.*
[894] *Id.*
[895] *Id.*
[896] *Id.* at 25; *In re the App. of Minn. Energy Resources Corporation for Auth. to Increase Rates for Natural Gas Service in Minn.*, Docket No. G-007, 011/GR-10-977, Findings of Fact, Conclusions, and Order, at 20-21 (July 13, 2012); *See also* 2013 MERC Rate Case Order, at 32–33; *In re the Appl. of Minn. Energy*

Likewise, the PUC has rejected injecting company-specific factors into the analysis *after* running a model. The specific risks "have been subsumed into the mix of characteristics of the companies of the proxy groups[.]"[897] Further, "adjusting for isolated, company-specific characteristics cutting only in favor of a higher return would improperly skew the DCF analysis."[898] According to the PUC, to calculate the cost of equity it is better to use one strong model which incorporates

> all publicly available information about the Company (or its closest proxies), current market conditions, and investors' expectations regarding future market conditions. Factoring uncertainty about future market conditions into the cost-of-equity equation at the end of the process would introduce speculation and double-counting; it would not enhance accuracy.[899]

This case is similar to cases where the PUC determined that

> the Company's three-model method compounds the subjectivity in each of the three models by requiring the analyst to synthesize their results, using subjective criteria. It is much more straightforward to choose the strongest model, use its results as a baseline, and use the results of the other models as additional information.[900]

Here Applicant argues for a multi-model approach with both subjective factors and double counting. Applicant argues for the Risk Premium models as opposed to the DCF models, in opposition to the PUC's favored approach. Further, Applicant engages in double-counting by adjusting the model calculations up based on the risk factors that were, or should have been, factored into the proxy group. This additional subjectivity is frowned upon by the PUC.

The proxy group should not be arbitrarily limited so as to skew the calculated ROE high. The PUC has rejected exclusion of potential proxy companies with ROEs that are excessively low when the same exclusion is not applied to companies that have a high ROE.[901] "While the addition of…one firm will not produce a large change in the ultimate result, the Commission concludes that including [the company with the low ROE] would

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Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minn., Docket No. G-007, 011/GR-08-835, Findings of Fact, Conclusions of Law, and Order, at 10–11 (June 29, 2009).

[897] *In re the App. of Minn. Energy Resources Corp. for Authority to Increase Rates for Natural Gas Service in Minn.*, MPUC Docket No. G-011/GR-15-736, Findings of Fact, Conclusions, and Order at 26.

[898] *Id.*

[899] *Id*. at 27.

[900] *Id.* at 26; *citing In re the App. of Minn. Energy Resources Corp. for Auth. to Increase Rates for Natural Gas Service in Minn.*, Docket No. G-007, 011/GR-10-977, Findings of Fact, Conclusions, and Order, at 20-21 (July 13, 2012); *See also* 2013 MERC Rate Case Order, at 32–33; *In re the App. of Minn. Energy Resources Corp. for Auth. to Increase Rates for Natural Gas Service in Minn.*, Docket No. G-007, 011/GR-08-835, Findings of Fact, Conclusions of Law, and Order, at 10–11 (June 29, 2009).

[901] *See e.g. In re the App. of Otter Tail Corp. d/b/a Otter Tail Power Comp. for Auth. to Increase Rates for Electric Utility Service in Minn.*, MPUC Docket No. E-017/GR-07-1178, Findings of Fact, Conclusions of Law, and Order at 58 (Aug. 1, 2008).

provide a more balanced analysis than excluding it."[902] Thus, Applicant's exclusion of companies with a ROE below 8 percent should be rejected.

Applicant believes it has a capital structure sufficient to support "investors' confidence and [its] credit rating."[903] The proposed capital structure mitigates claims about needing a higher ROE to attract capital, because it has already mitigated some risk. The Department agrees with this position, in part. According to Dr. Amit, "debt financing increases the volatility of future earnings since a company with more debt relative to similar companies is expected to pay more in annual interest."[904] Further, if Applicant loses a significant portion of its native load (a taconite facility closes), it can sell power wholesale on the MISO Day 2 energy market, mitigating revenue losses.[905] Applicant disputes this idea, arguing that declining wholesale prices have limited it's ability to recover lost industrial customers margins.[906] In 2016, according to Applicant, it recovered only 57 percent of the lost margin from industrial customers in the wholesale market when compared to what it would have earned selling to large power customers.[907] However, this rate case and the EITE credit are both striving to lower the cost of electricity to many of the large power customers, so the difference in lost margin may be much less in the future when selling on the wholesale market.

Applicant points to its high industrial customer concentration as evidence of being a relatively high-risk investment. The Department employs an economic analysis to demonstrate that Applicant, and specifically its holding company, ALLETE, is not generally more risky than similar companies.

First, the Department created its own proxy group to run the models.[908] Dr. Amit screened companies to select those that operate in a similar business, under similar regulatory environments, and similar financial and economic conditions.[909]

Dr. Amit measured the companies that survived these screens for financial risk and compared them to Applicant.[910] Financial risk was measured using the S&P bond rating, which is based on S&P's assessment of the company's ability to meet its future debts.[911] Dr. Amit also measured the proxies' volatility of the rate of return of their stock using the beta and the Standard Deviation of Price Changes (STDPC).[912]

Dr. Amit then measured risk based on the volatility of net income and the realized rate of return.[913] Dr. Amit used the coefficient of variation (COV), which is the standard

[902] *Id.*
[903] Tr. Vol 2 at 54 (Cutshall).
[904] Ex. 600 at 11 (Amit Direct).
[905] Ex. 600 at 54-56 (Amit Direct).
[906] Ex. 35 at 5 (Hevert Rebuttal).
[907] *Id.* at 14.
[908] Ex. 606 at EA-S-5 (Amit Surrebuttal).
[909] Ex. 601 at 12 (Amit Direct).
[910] *Id.* at 13-14.
[911] *Id.* at 12.
[912] *Id.* at 12-13.
[913] Ex. 606 at 13 (Amit Surrebuttal).

deviation divided by the mean, as the indicator of volatility. The higher the number, the riskier the company.[914] The mean for the 17 companies in the proxy group, looking at data from 2006 through 2016, is 0.48. ALLETE's COV for that period is 0.35, indicating it is significantly below the mean.[915]

The Department's analysis included errors, however. The data for at least some of the companies was from 2005 through 2015, not 2006 through 2016.[916] Some of the data is older than represented. The data for one proxy, PNM Resources, does not match its 10-K, and it is unclear where the data came from. Thus, the data is not accurate. This is important because PNM Resources has the highest COV at 2.86. Giving the rest of the data the benefit of the doubt, a calculation excluding PNM Resources results in a mean of 0.33, not 0.48. Thus, Applicant's risk is higher than the mean, but not significantly.[917]

Applicant's risk level is incorporated into the analyses used under the DCF models. The Department's application of the Constant-Growth DCF model resulted in a ROE of 8.63 percent, and the Two-Growth DCF model resulted in a ROE of 8.77 percent.[918] The average between the two, 8.7 percent, is the Department's recommended ROE.[919] These numbers include flotation costs because the issuance costs are related to the cost of capital and it is more appropriate to capitalize them than to expense them.[920] Capitalizing issuance costs also helps ensure the reasonableness of the rate of return.[921] Recovering flotation costs is reasonable because the PUC requires such costs to be recovered in a manner that does not double-count the costs incurred.

E. Conclusion

The errors in the Department's analysis were implementation errors and so do not render the Department's approach flawed. The overall analysis must be conducted again, however, based on all of the recommendations the PUC determines to require Applicant to follow.

The Administrative Law Judge finds that Applicant's capital structure and proposed ROE may not be reasonable because they are based on flawed modelling and analysis. Applicant should be required to perform calculations using the two variants of the DFL model using the Department's proxy group, without additional screening or subjective analysis. The average of the range of the resulting ROE should be adopted as just and reasonable.

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[914] *Id.*
[915] *Id.* at EA-S-5 (Amit Surrebuttal).
[916] Tr. Vol 3 at 207-15 (Amit).
[917] The data does show that Xcel Energy, the other Minnesota company in the proxy group, has the lowest COV at 0.04. Applicant is correct when it asserts it faces greater risk than at least one Minnesota company.
[918] Ex. 606 at 6, EA-5-3 (Amit Surrebuttal).
[919] *Id.*
[920] Ex. 603 at 17 (Amit Rebuttal).
[921] Ex. 601 at 24-25 (Amit Direct).

IV. RATE DESIGN

A. Legal Standard

Rates must be just and reasonable and "shall not be unreasonably preferential, unreasonably prejudicial, or discriminatory, but shall be sufficient, equitable, and consistent in application to a class of consumers."[922] The Applicant bears the burden of proving, by a preponderance of the evidence, that its proposed rate design is just and reasonable.[923] Any doubt about the reasonableness of Applicant's proposals should be resolved in favor of customers.[924]

The rate design process is quasi-legislative in nature.[925] Policy concerns play a major role in rate design. The Commission must balance a wide range of concerns, including: "economic efficiency, continuity with prior rate cases; ease of understanding; ease of administration; promotion of conservation; ability to pay; ability to bear, deflect, or otherwise compensate for additional costs' and in particular, the cost of service."[926] Further, the PUC must ensure consumers can obtain adequate, efficient, and reasonable electric service at rates that fairly compensate the utility for its costs afford it an opportunity to earn a reasonable profit.[927] As long as Applicant has met its burden, other proposals are not considered.[928]

B. Sub-issues

i. Class Cost of Service Study (CCOSS)

a. Fixed Production Cost Classification

Applicant's Position

Applicant seeks to have its fixed production revenue-related items classified as 100 percent demand.[929] According to Applicant, the fixed production items are those costs

[922] Minn. Stat. § 216B.03.
[923] Minn. Stat. § 216B.16, subd. 4.
[924] Minn. Stat. § 216B.03.
[925] *St. Paul Area Chamber of Commerce v. Minnesota Pub. Serv. Comm'n,* 251 N.W.2d 350, 358 (Minn. 1977).
[926] *In re Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E-002/GR-10-971, Findings of Fact, Conclusions, and Order at 14 (May 14, 2012); *see also* Minn. Stat. §§ 216B.03, .05, .16.
[927] Minn. Stat. § 216B.16; *In re Pet. of N. States Power Co. for Auth. to Change its Schedule of Rates for Elec. Serv. in Minn.*, 416 N.W.2d 719, 722-723 (Minn. 1987); *In re Pet. of Minn. Power & Light Company, d.b.a. Minnesota Power, for Auth.to Change its Schedule of Rates for Elec. Utility Serv. Within the State of Minn.*, 435 N.W.2d 550, 554 (Minn. App. 1989).
[928] *See, e.g., In re Pet. of N. States Power Co. for Auth. to Change its Schedule of Rates for Elec. Serv. in Minn.*, 416 N.W.2d 719, 726 (Minn. 1987) ("When, in the Commission's judgment, a petitioner utility has failed to establish the reasonableness of costs….the Commission itself may compute a hypothetical capital structure that will afford an ultimate determination of a reasonable rate.").
[929] Ex. 81 at 3-4 (Shimmin Rebuttal).

and associated revenues that do not vary with electricity production at the time electricity is produced.[930] Thus, argues Applicant, they are not both demand- and energy-related.[931]

Challenges to Applicant's Position

The Department and OAG argue that the Applicant's proposal is inconsistent with cost-causation and that it would be more appropriate to classify fixed production revenue requirement items based on Applicant's annual system load factor (its average demand divided by peak demand for the given period).[932] The Department argues that using the Applicant's load factor as the percentage of fixed production that is energy-related, and one-minus the Applicant's system load factor as the percentage that is demand-related.[933]

Analysis and Conclusion

Applicant has shown its proposal is just and reasonable. Applicant has utilized this classification for several rate cases with PUC approval, as this classification is consistent with NARUC guidelines and consistent with principles of tying cost classifications to the cause of those costs (cost-causation).[934]

It is not necessary to consider challengers' proposals to classify fixed production revenue-related items differently where the Applicant has demonstrated that its proposal is just and reasonable. The PUC is not charged with selecting the arguably best method when making determinations about rate design. Rather, the question is whether the evidence justifies the conclusion sought by Applicant when considered together with the PUC's responsibilities to enforce the state's policies on electric service.[935] On the sub-issue of fixed production cost allocation, Applicant has met its burden.

b. CCOSS Model and Allocation Methods

Applicant's Position

Applicant adopted a Peak & Average (P&A) allocation method, utilizing the Company's peak.[936] Applicant has used this allocation method going back to, at least, 1980 when the Department recommended it.[937] Applicant has used it in its last two rate cases.[938] The underlying reasons this method has been used in the past is because it is a method discussed in the NARUC Manual and it works with systems like Applicant's

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[930] Ex. 610 at 9-10 (Collins Direct).
[931] Ex. 81 at 3-4 (Shimmin Rebuttal).
[932] Ex. 610 at 10 (Collins Direct); Ex. 511 at 5-6 (Nelson Rebuttal).
[933] Ex. 81 at 4 (Shimmin Rebuttal).
[934] *Id.* at 3-4.
[935] Minn. Stat. § 216B.16, subd. 4; *In re Pet. of N. States Power Co. for Auth. to Change its Schedule of Rates for Elec.Serv. in Minn.*, 416 N.W.2d 719, 722 (Minn. 1987).
[936] Applicant's Initial Br. at 134 (Sept. 12, 2017) (eDocket No. 20179-135459-02).
[937] Ex. 78, SJS-1 at 7-8 (Shimmin Direct); *see also* Ex. 81 at 5 (Shimmin Rebuttal).
[938] Ex. 81 at 6 (Shimmin Rebuttal).

which are designed to provide large amounts of energy to a small number of customers along with providing sufficient capacity to meet peak loads, according to Applicant.[939]

Challenges to Applicant's Position

OAG and LPI challenge Applicant's allocation method. OAG argues that Applicant's allocation method does not accurately reflect cost-causation of its demand costs and is highly susceptible to year-to-year variation from Applicant's sales.[940] According to OAG, Applicant's system peak does not align with the MISO peak – Applicant's peak is in the winter while MISO's peak is in the summer.[941] Thus, argues OAG, the Applicant's reliance on the MISO – summer – peak is inconsistent with Applicant's actual peak and therefore the cost-causation related to production is not accurately calculated.[942]

In addition, OAG argues that because Applicant bases its coincident peak on a single hour from a single year, there are extremely variable outcomes from one year to the next.[943] These outcomes can shift large portions of Applicant's costs from one class to another based on electricity consumption in a single hour. This brings the model's accuracy into question, according to OAG.[944]

LPI argues that Applicant's cost allocation methodology results in double-counting and, therefore, results in an unjust and unreasonable error in Applicant's CCOSS.[945] According to LPI, the P&A allocator does not reasonably reflect class cost of service because it double-counts average demand in both the peak demand factor (or "P") and the average demand factor (or "A"), thereby skewing the allocation factor in favor of smaller customers and to the detriment of larger customers.[946] This is the result because, according to LPI, the P&A methodology "does not accurately measure the distinct load characteristics of each rate class and the amount of capacity needed to serve the class demands."[947] The double-counting of energy consumption predominately allocates production costs on only energy demands, according to LPI.[948]

LPI argues that the 3 winter 1 summer (3W/1S) method for cost allocation is a fair and reasonable methodology for allocating production costs to the customer classes.[949] The 3W/1S methodology accurately reflects production capacity cost and class load cost-

[939] *Id.*
[940] OAG Initial Br. at 130 (Sept. 12, 2017) (eDocket No. 20179-135457-02).
[941] Ex. 78 at 17 (Shimmin Direct).
[942] *Id.*; OAG Initial Br. at 132 (Sept. 12, 2017) (eDocket No. 20179-135457-02).
[943] Ex. 509 at 56 (Nelson Direct).
[944] OAG Initial Br. at 132 (Sept. 12, 2017) (eDocket No. 20179-135457-02).
[945] LPI Reply Br. at 27 (Sept. 28, 2017) (eDocket No. 20179-135858-02).
[946] Ex. 100 at 20 (Gorman Direct).
[947] Ex. 110 at 12 (Gorman Surrebuttal).
[948] *Id.*
[949] LPI Initial Br. at 26-27 (Sept 12, 2017) (eDocket No. 20179-135470-02).

causation relationship, according to LPI.[950] Using the 3W/1S method, large power customers should see an overall rate decrease.[951]

Analysis

While OAG raises theoretical questions about the Applicant's cost allocation method, it did not present evidence demonstrating its theories. In other words, OAG raised questions about the Applicant's method, but did not demonstrate Applicant's method resulted in inaccurate numbers or was otherwise unjust or unreasonable.[952]

LPI's arguments come closer, but not close enough. Applicant carries the burden of proof and must show its proposal is just and reasonable, not the best. Applicant has presented evidence that its allocation methodology, one of several that may be used, is an accepted methodology in the industry and by the PUC. To overcome this, a challenger must show that Applicant's methodology results in inaccurate numbers, not merely numbers that the challenger does not like. Various allocation models result in different numbers. Despite LPI's criticisms of the P&A method, it has not shown the methodology itself is no longer accepted in the industry, that was improperly applied and generated inaccurate numbers, or any other facts to show the results are unjust and unreasonable.

Conclusion

Applicant's P&A allocation method recognizes the role that customer energy consumption and customer demand play in causing utilities to invest in production plant. Applicant has shown the use of this method is just and reasonable and it should be approved.

c. Functionalization of 46kV Lines

In 2002 the PUC approved Applicant's classification of its 46 kV system as distribution.[953] OAG questions this determination based on how the PUC approved another utility's functionalization of such assets in 2010.[954] Because the PUC approved Applicant's classification of its 46 kV system as distribution, Applicant has demonstrated that, by a preponderance of the evidence, this classification is just and reasonable. OAG's challenge to the PUC's prior determination about the classification need not be considered as part of this rate case.

d. Classification of Distribution System (Meters and FERC Accounts 364-369)

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[950] Ex. 101 at 32 (Gorman Direct).

[951] Ex. 100, MPG-B at 75 (Gorman Direct – Trade Secret).

[952] *See, e.g.,* OAG Initial Br. at 133 (Sept. 12, 2017) (eDocket No. 20179-135457-02) ("This casts doubt on the final result of the Company's CCOSS, which the ALJ and the Commission must consider.").

[953] *In re the Pet. by Minn. Power for Approval of Asset Separation and Accounting Methodology*, MPUC Docket No. E015/M-01-1416, Order Approving Petition, With Clarifications and Requirements at 2 (Aug. 8, 2002).

[954] Ex. 509 at 26-29 (Nelson Direct).

1. Meters

Since 2009, Applicant has been purchasing and installing advanced metering infrastructure (AMI) meters.[955] Applicant has classified and allocated its meters as 100 percent customer costs because meters are required to measure the amount of energy flow to a customer regardless of the specific quantity of demand or energy used.[956] According to Applicant, it does not matter whether the meter is a "dumb" meter or AMI meter because in either case the meter is necessary for a customer to obtain electricity.[957] Applicant considers OAG's recommendation to be unfair to large power users because it would shift cost from residential customers to large power users.[958]

OAG "recommends" that meters should be classified as one-third energy, one-third demand, and one-third customer costs.[959] This is because of the diverse functionality of the AMI meters which can help lower demand and energy costs.[960] Further, according to OAG, a portion of the cost of meters is required to directly connect each customer to the distribution system.[961] In addition, according to OAG, the PUC has recently determined that AMI meters providing controlled demand service "are more appropriately understood as demand or energy costs" which benefit the utility's system as a whole.[962] Thus, such costs should be excluded from the calculation of customers' marginal cost.[963]

The preponderance of the evidence shows that the cost of the AMI meters is more than exclusively a customer cost. However, the evidence is not clear on the proportion of the costs to be allocated. Based on the evidence in the record, it appears the customer cost would be more than one-third, while clearly not 100 percent. Because the record does not show what the correct allocation is, the question should be resolved in favor of the ratepayers.[964] The PUC should exclude from the calculation of each customer class the cost of the meters.

2. Other Distribution Assets (FERC Accounts 364-369)

FERC accounts 364 through 369 consist of poles, overhead distribution lines, underground distribution lines, overhead and underground transformers, and costs for service lines.[965] Applicant classifies and allocates these assets as 13.4 percent demand and 86.6 percent customer components.[966] Applicant does this because these facilities

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[955] *Id.* at 37*;* Ex. 49 at 64 (Fleege Direct).
[956] Applicant Initial Br. at 142 (Sept. 12, 2017) (eDocket No. 20179-135459-02); Ex. 509 at 37 (Nelson Direct).
[957] Applicant Initial Br. at 143 (Sept. 12, 2017) (eDocket No. 20179-135459-02).
[958] Ex. 81 at 18 (Shimmin Rebuttal); Ex. 509 at 41 (Nelson Direct).
[959] Ex. 509 at 38 (Nelson Direct).
[960] *Id.* at 39.
[961] *Id.*
[962] *In re Application of Otter Tail Power Co. for Auth. to Increase Rate for Elec. Serv. in Minn.*, MPUC Docket No. 15-1033, Findings of Fact, Conclusions, and Order at 75 (May 1, 2017).
[963] *Id.*
[964] Minn. Stat. § 216B.03.
[965] Ex. 81 at 26 (Shimmin Rebuttal); Ex. 611 at 22-23 (Collins Rebuttal).
[966] Ex. 8, O-1 at 29 (Initial Filing Vol. V); Ex. 81 at 26 (Shimmin Rebuttal); Ex. 611 at 29 (Collins Rebuttal).

deliver energy to customers, which is necessary regardless of demand levels, and are sized to handle customers' demand needs.[967] Applicant argues that this is consistent with the NARUC Manual.[968]

OAG argues that Applicant classifies too much of the distribution system as a customer cost.[969] OAG argues the "basic customer" method is the most reasonable, but also recommends that P&A and "minimum system" methods be incorporated into revenue apportionment decisions.[970]

Applicant has shown that its classification and allocation of other distribution assets (referred to here) are just and reasonable. Thus, other recommended approaches need not be considered.

ii. Revenue Apportionment

Applicant's Position

Applicant argues that its proposed revenue apportionment is reasonable and should be adopted in this proceeding.[971] Applicant argues that its approach in altering revenue apportionment will balance the needs of the Company's various classes, while moving each class somewhat closer to its cost of service.[972]

Challenges to Applicant's Position

The Department, OAG, ECC, AARP, LPI, MCC, and Wal-Mart all challenged Applicant's revenue apportionment. The Department challenges Applicant's proposed increase for the residential class – 15 percent – because it comes one year after the implementation of increases of 4.45 to 6.49 percent resulting from the implementation of the EITE rate.[973] The total increase of approximately 20 percent in such a short period of time, argues the Department, will result in rate shock and is unreasonable.[974] According to the Department, the PUC limited Applicant's 2009 residential rate increase to 3.9 percent because rates had increased 12 percent the previous year.[975] Thus, the Department argues, the proposed increase at this time is too high.[976] As a result, the Department recommends limiting the residential rate increase to no more than 10 percent.[977]

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[967] Ex. 81 at 26 (Shimmin Rebuttal).
[968] *Id.*
[969] OAG Initial Br. at 125 (Sept. 12, 2017) (eDocket No. 20179-135457-02).
[970] Ex. 509 at 35, 44 (Nelson Direct).
[971] Applicant Initial Br. at 145 (Sept. 12, 2017) (eDocket No. 20179-135459-02).
[972] Applicant Initial Br. at 146 (Sept. 12, 2017) (eDocket No. 20179-135459-02).
[973] Ex. 614 at 24, MNZ-5 (Zajicek Direct).
[974] *Id.*
[975] *Id.* at 26-27.
[976] *Id.* at 27-28.
[977] *Id.* at 28-30.

OAG also argues that the proposed 15 percent residential rate increase is too high and, therefore, unfair to the residential class.[978] Further, according to OAG, Applicant's proposal focuses almost exclusively on aligning the residential rate with the cost of service, ignoring all other policy goals and concepts of equity.[979] Part of the problem, according to OAG, is that the CCOSS analysis is based on analytical flaws (discussed throughout herein) that result in exaggerated costs for the residential class.[980]

ECC argues that any increase in residential rates should be limited to the overall requested increase of 6.1 percent.[981] According to ECC, the proposed 15 percent increase combined with the proposal to change the rate design to a two-block model will impose the largest percentage rate increase on ratepayers least able to afford the increase.[982] This, argues ECC, violates Minn. Stat. § 216B.16, subd. 15, which requires the PUC to consider customers' ability to pay when setting rates.[983]

AARP shares the concern that residential customers who are older are being asked to incur a 15 percent rate increase at the same time they are being required to subsidize certain large industrial customers through the EITE rate.[984] AARP argues that in order to ensure the increases do not become unmanageable for its constituents, no customer class should be subject to an increase of more than 9.29 percent.[985] According to AARP, this would implement the principle of fairness by distributing any revenue increase among the customer classes. Second, it would help to move each class closer to paying its cost of service, but does so in a manner that avoids extreme rate changes to any particular group of customers. And third, setting a reasonable limit on class increases recognizes that cost-of-service studies are estimates based on numerous assumptions that may change over time.[986] AARP argues that dramatic shifts in cost allocation that are unrelated to overall changes in the revenue requirement should not automatically translate into dramatic changes in rates.[987]

LPI takes a different perspective on the proposed revenue apportionment, arguing that large power customers receive no rate increase, in order to address a growing gap in their cost of service compared to residential customers.[988] For example, LPI argues that since 2005, rates for large power customers have increased over 70 percent while rates for the residential class have increased 50 percent.[989] LPI also argues that any class can experience rate shock and that there is no evidence in the record that large industrial

[978] OAG Initial Br. at 122 (Sept. 12, 2017) (eDocket No. 20179-135457-02).
[979] *Id.*
[980] *Id.*
[981] Ex. 200 at 24 (Marshall Direct).
[982] ECC Initial Brief at 1 (Sept. 12, 2017) (eDocket No. 20179-135453-01).
[983] *Id.*
[984] AARP Initial Br. at 4 (Sept. 12, 2017) (eDocket No. 20179-135471-01).
[985] Ex. 400 at 3, 12 (Rubin Direct).
[986] *Id.* at 11.
[987] *Id.*
[988] LPI Initial Br. at 37 (Sept. 12, 2017) (eDocket No. 20179-135470-02).
[989] *Id.* at 34; Evidentiary Hearing Tr. Vol. 2 at 116 (Podratz).

customers have more of an ability to pay their utility bills than residential customers do.[990] LPI argues that the competitiveness of large power customers is a direct benefit to the residential class because those industries employ many residential customers and, therefore, they have a shared interest.[991]

MCC largely shares LPI's view, and argues that reducing the gap in the cost of service between residential customers on the one hand, and commercial and industrial customers on the other, is necessary to remedy a currently unjust and unreasonable revenue allocation.[992] MCC argues that the focus must be on the cost of service when setting rates.[993] For those residential ratepayers for whom a rate increase poses a hardship, MCC argues the remedy is in government support, not a significant cross-class subsidy from commercial and industrial customers.[994]

Finally, Wal-Mart also argues for a continued move toward cost when setting rates.[995] Wal-Mart argues for a gradual shift toward cost, so long as reductions in revenue requirements reduce the cost disparity between classes.[996] According to Wal-Mart, having rates reflect costs encourages efficient use of resources.[997]

Analysis

The ratepayers are, to a degree, pitted against each other on this sub-issue. In general, the residential customers, whose rates have been largely subsidized by the larger power consumers, are faced with rate increases which the large power customers do not think go far enough in terms of bringing both groups closer to paying their cost of service. This has long been an issue for the community due to the unique circumstance of Applicant relying on a small group of large power customers for the majority of its income. There is also evidence that the residential customers tend to use more electricity than customers in other regions due to the age and location of their homes, and because their lower-than-average income levels which, for many residential customers, impacts their ability to improve homes or sustain higher rents for more energy efficient homes.[998]

It is also true that the large power customers are part of the economic life-blood of the region. Residential customers may not be employees of these industries, but their economic opportunities largely exist to support the industries and the industry employees

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[990] LPI Initial Br. at 34 (Sept. 12, 2017) (eDocket No. 20179-135470-02); Evidentiary Hearing Tr. Vol. 2 at 34, 35, 121, 129 (McMillan, Podratz).
[991] LPI Initial Brief at 34-35 (Sept. 12, 2017) (eDocket No. 20179-135470-02); Evidentiary Hearing Tr. Vol. 1 at 36-37 (McMillan).
[992] MCC Initial Brief at 6-10 (Sept. 12, 2017) (eDocket No. 20179-135461-01); Ex. 300 (Blazar Direct). (Exhibit 300 lacks page numbers).
[993] MCC Initial Brief at 6-10 (Sept. 12, 2017) (eDocket No. 20179-135461-01); Ex. 300 (Blazar Direct). (Exhibit 300 lacks page numbers).
[994] MCC Initial Brief at 9-10 (Sept. 12, 2017) (eDocket No. 20179-135461-01); Ex. 300 (Blazar Direct). (Exhibit 300 lacks page numbers).
[995] Wal-Mart Initial Br. at 11 (Sept. 12, 2017) (eDocket No. 20179-135445-01).
[996] *Id.*; Ex. 151 at 19 (Chriss Direct).
[997] Wal-Mart Initial Br. at 11 (Sept. 12, 2017) (eDocket No. 20179-135445-01).
[998] *See generally* Ex. 200 (Marshall Direct); Ex. 400 (Rubin Direct).

in other ways. People are employed in the businesses, schools, health care facilities, and all other parts of the community that are necessary for a civilized social structure. Thus, a balance must be achieved that permits all parties to prosper and share in the rewards of economic progress that is currently driven, in large part, by the large power class.

In 2010, when Applicant's last general rate increase was approved, economic conditions were in the beginning of a slow recovery from the recession of 2008. For that reason, the PUC shielded residential customers from the bulk of a rate increase.[999] No such economic distress is gripping the region today. Further, the state has implemented a policy to improve the economic prosperity of the region, which entails the majority of ratepayers paying for rate decreases for EITE electric customers.[1000] The consideration of these factors is important when apportioning revenue.

Conclusion

Applicant's proposed revenue apportionment is not just and reasonable. The Administrative Law Judge recommends the PUC apportion revenues to permit Applicant to increase its revenues from each customer class with the possible exception of large power customers. It is also recommended that the rates shift a modest amount closer to the estimated cost of service for each class. Since the cost of service cannot be determined with precision, is not the only factor to consider. To comply with state policy driving the EITE credit, it is recommended that the large power class receive the smallest increase, if any, and that all other customers' rates be increased so as to reduce each class's revenue deficiency by the same percentage. Some classes will see larger increases than others. However, it is recommended no class receive an increase of more than 10 percent. This approach is recommended in order to justly balance the needs and expectations of all customers and the Applicant. It will help to ensure the economic engines of the region remain strong and prevent rate shock among any customer class.

iii. Residential Service Charge

Applicant's Position

Applicant seeks to increase the residential service charge – a charge to recover some of the service connection costs - from $8.00 to $9.00.[1001] Applicant argues that the CCOSS indicates actual monthly residential service connection costs are $26.35.[1002] The increase, however, only mirrors inflation over the past seven years, 13 percent, and is much smaller than the increases imposed by neighboring cooperative utilities over that period.[1003]

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999 *In re the Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E-015/GR-09-1151, Findings of Fact, Conclusions, and Order at 57 (Nov. 2, 2010).
1000 *See* Minn. Stat. § 216B.1696.
1001 Ex. 82 at 60-61 (Podratz Direct); Ex. 86 at 25-31 (Podratz Rebuttal); Ex. 87 at 4-9 (Podratz Surrebuttal).
1002 Ex. 82 at 60 (Podratz Direct).
1003 *Id*.

Challenges to Applicant's Position

OAG, ECC and AARP argue that the customer service charge should not be changed. OAG argues that the customer service charge should remain at $8 because the "customer costs" Applicant found in its CCOSS is flawed.[1004] The flaw, according to OAG, is that the CCOSS result is based on embedded costs rather than marginal costs.[1005] In addition, OAG argues that the following principles support keeping the customer service charge at $8:

- Vulnerable customers should have access to enough electricity to fulfill their basic needs at affordable rates;
- Rates should be equitable and generally based on cost-causation, unless necessary to meet a state policy-objective;
- Rates should allow the utility the opportunity to recover its revenue requirement;
- Rates should encourage conservation and energy efficiency;
- Rates should reduce coincident peak demand;
- Rates should be stable, understandable, and provide customer choices;
- Rates should encourage economically efficient decision-making; and,
- Rates should be aligned with wholesale market prices that reflect the varying price of electricity.[1006]

ECC also argues that the service change should not change because it is a fixed charge and will not influence customers' conservation efforts.[1007] In addition, according to ECC, an increase in this charge will disproportionately impact low-use residential customers who are often low income customers.[1008] AARP shares this concern and makes a similar argument.[1009]

AARP also argues that the existing $8.00 charge "appears to collect a minimally acceptable about of revenues from the residential class…sufficient…to cover the costs associated with metering, meter reading, and residential service connections."[1010] AARP argues that this is fair because according to Applicant's P&A CCOSS, the cost of providing residential customers with meters and service lines represents approximately 11 percent of the cost of service. The existing customer service charge results in

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[1004] OAG Initial Br. at 141 (Sept. 12, 2017) (eDocket No. 20179-135457-02); OAG Reply Br. at 23 (Sept. 28, 2017) (eDocket No. 20179-135867-01).
[1005] OAG Initial Br. at 141 (Sept. 12, 2017) (eDocket No. 20179-135457-02); OAG Reply Br. at 23 (Sept. 28, 2017) (eDocket No. 20179-135867-01).
[1006] Ex. 509 at 62-66 (Nelson Direct); OAG Initial Br. at 119 (Sept. 12, 2017) (eDocket No. 20179-135457-02).
[1007] Ex. 200 at 25-26 (Marshall Direct).
[1008] *Id.*
[1009] AARP Initial Br. at 16-17 (eDocket No. 20179-135471-01).
[1010] *Id.*

approximately $10 million, or 11 percent of the approximately $90 million of annual residential revenues, before adjustments, according to AARP.[1011]

Analysis

The evidence in the record does not demonstrate the accuracy of Applicant's claimed basic cost of residential service. The CCOSS is flawed, and Applicant has not shown how $26.35 per month was arrived at.[1012] Further, Applicant's argument about its residential service charge being significantly lower than neighboring cooperative utilities is unconvincing. The utilities it uses for comparison are cooperatives precisely because they are in rural areas where the cost of connecting customers is much higher than more urban areas. Thus, the basic service charge for those rural customers is naturally higher.

Conclusion

Applicant has not demonstrated it is just and reasonable to increase the $8.00 residential service charge. The Administrative Law Judge recommends that the PUC not permit Applicant to increase the residential service charge from $8.00 to $9.00.

iv. Block Rate Design

Applicant's Position

Applicant proposes to begin to eliminate the current block rate structure. In this proceeding, Applicant proposes to reduce the current five-block residential energy rate structure to a two-block rate structure.[1013] The five-block rate design was a pilot put in place as a result of Applicant's 2009 rate case.[1014]

According to Applicant, there is no evidence the pilot rate structure has resulted in conservation and lower energy consumption.[1015] Applicant argues that the current five-block structure presents added complexity when offering rates that are layered on top of the existing structure.[1016] Eliminating the five-blocks, or reducing them to just two blocks, will permit future rate designs to be simpler, easier to modify, analyze, administer, and understand, according to Applicant.[1017] Applicant also argues that its customers must pay higher rates as their usage increases, while other investor-owned utilities' customers' rates decrease as their usage goes up.[1018] Finally, Applicant argues that its residential customers who use between 500 and 750 kWh per month pay less per kWh than similarly situated customers of other Minnesota investor-owned utilities.[1019]

[1011] *Id.*
[1012] Ex. 6, Sched. E-2 at 104 (Initial Filing Vol. 4).
[1013] Ex. 82 at 58-59 (Podratz Direct).
[1014] *Id.* at 57.
[1015] *Id.* at 58.
[1016] *Id.* at 58-59; Ex. 87 at 11 (Podratz Surrebuttal).
[1017] Ex. 87 at 10-11 (Podratz Surrebuttal).
[1018] Ex. 82 at 58 (Podratz Direct).
[1019] *Id*.

Challenges to Applicant's Position

The Department, OAG, CEO, ECC, and FDL are all opposed to Applicant's proposal to eliminate the residential block-rate design. OAG objects to the proposal to reduce the number of rate blocks from five to two because this would shift revenues from higher usage customers to lower usage customers and cause about 80 percent of customers to see a large increase as a result of the change.[1020] This change, argues OAG, is unfair and inconsistent with its policy goals.[1021] OAG argues that there is no evidence the current rate structure is confusing or detrimental to customers.[1022] Finally, OAG argues that Applicant has provided no evidence to support its claim that the rate structure is not responsible for the reduced energy consumption of its customers.[1023]

The Department, CEO, ECC, AARP, and FDL all agree that Applicant's rate block structure should be reduced from five to four blocks.[1024] According to the agreement, the proposed four-block rate structure is consistent with the PUC's Order in the 2009 rate case and will simplify the rate design.[1025] This proposed structure would look like the following, with the "revenue requirement" representing the amount of revenues per kWh collected from residential customers through consumption charges:

Blocks	Inclining Block Adjustment
0 kWh to 400 kWh	76%
401 kWh to 800 kWh	Revenue requirement
801 kWh to 1200 kWh	124%
Over 1200 kWh	150%

Applicant could base the calculations on the final determination of the overall revenue requirement allocated to the residential class, the amount of residential revenues collected through the customer charge, and any miscellaneous service charges.[1026] The Department notes that this design, coupled with no increase in the residential service charge and a reduction in the revenue requirement increase from what Applicant recommended, should reduce the impact on low-income customers while helping to eliminate the residential class intra-subsidies.[1027]

Analysis

The question is not: who presents the best or most reasonable proposal for the rate design. Rather, the question is whether Applicant has presented a proposal that is

[1020] OAG Initial Br. at 139-40, 147 (Sept. 12, 2017) (eDocket No. 20179-135457-02).
[1021] *Id.* at 136, 140 (nine policy goals).
[1022] *Id.* at 147.
[1023] *Id*. at 148.
[1024] *In re the Application of Minn. Power for Auth. to Increase Rates for Elect. Serv. in Minn.*, MPUC Docket No. E015/GR-16-664, Stipulation of Settlement (Sept. 12, 2017).
[1025] *In re the Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E015/GR-09-1151, Findings of Fact, Conclusions, and Order at 56, 65-66 (Nov. 2, 2010).
[1026] *Id.*
[1027] Department Initial Br. at 203 (Sept. 12, 2017) (eDocket No. 20179-135469-01); Ex. 616 at 20-21 (Zajicek Surrebuttal).

just and reasonable.[1028] Applicant's proposal to reduce and eventually eliminate the inverted five-block rate design is not just and reasonable.

The current five-block structure appears to be successfully accomplishing what the PUC intended: reducing consumption. This is consistent with the policy of the legislature.[1029] Applicant offers that there is no evidence the five block design is responsible for the reduced electric usage by customers. This could be true, but the PUC should put little stock in the argument. Consumption is down, which is evidence enough the policy goal is being met. Had Applicant demonstrated a thorough investigation and analysis of data to paint a picture of the weight of the various factors that go into energy usage, and that picture showed the PUC's five block rate design did not meaningfully contribute to the result, then Applicant may have made the case. Further, there is no evidence the current design is confusing to anyone, other than the Applicant's own statement that it is. Likewise, Applicant asserts without meaningful support that the current design is stifling further rate-design innovation.

Conclusion

All of Applicant's assertions and arguments about the current five-block inverted rate design fail to support or show that the design must be scrapped and its proposed two-block design is just and reasonable. Because Applicant's two-block design has not been shown to be just and reasonable, and Applicant was not part of the agreement of the Department, CEO, ECC, AARP and FDL, no further examination of other alternative plans is warranted. The Administrative Law Judge recommends the current block rate design not be changed.

v. CARE Program

Applicant's Position

Applicant proposes to make some superficial changes to the Customer Affordability of Electricity (CARE) rider. Applicant does not propose to change the $7.00 per month service charge for CARE customers, which funds the program.[1030] It does, however, propose to revise the "RATE MODIFICATION" section of the CARE rider to specify Customer/Service Charge and Energy Charge discounts instead of the existing CARE Customer Charge and Energy Charges. It also proposes to alter the language of the standard Residential Service Charge and Energy Charges, and the Affordability Surcharge terminology of the CARE rider. Applicant proposes changing the title to the more-descriptive "Low-Income Affordability Program Surcharge."[1031] According to Applicant, these changes will make it easier for customers to see the effect of being on the CARE rider.[1032] Applicant also proposes to reduce the number of energy charge blocks in the CARE rider rate to match its proposed two-block structure for standard

[1028] Minn. Stat. §§ 216B.03, .16.
[1029] Minn. Stat. § 216B.03.
[1030] Ex. 82 at 61-62 (Podratz Direct).
[1031] *Id.*
[1032] *Id.*

Residential rates.[1033] Applicant expects the fund for the program to be sufficient to cover its costs for the foreseeable future.[1034]

Challenges to Applicant's Position

Only ECC raises a concern about Applicant's proposal regarding the CARE rider. However, ECC does not challenge the proposed change and, instead, proposes its own change.[1035] ECC proposes that Applicant's CARE rider program be substantively changed to operate similar to another Minnesota utility's program for low-income customers.[1036] The goal is to ensure more eligible customers take advantage of the program.[1037] ECC's objections to Applicant's CARE rider proposal mirror its other objections to the proposed rate increases and proposed changes to the rate structure.[1038]

Analysis

Applicant's proposals for the CARE Rider program are not substantive. They are designed to, in Applicant's opinion, make clear to participants the benefit they receive from the program.

ECC's proposal challenges the substance of the current CARE Rider program. ECC wants to see substantive changes made to the program to improve its reach to eligible customers. Unfortunately, because Applicant did not propose substantive changes that would open the program up to such scrutiny, ECC's proposal should not be reviewed and considered at this time. Applicant has expressed willingness to discuss such changes with ECC, and the two parties should do so and, if possible, make a joint proposal in an appropriate proceeding before the PUC.

Conclusion

Because Applicant proposes no substantive changes to the CARE rider program, and only seeks to make changes in language to communicate more effectively with customers, Applicant has met its burden of demonstrating the majority of changes are just and reasonable. The only change not reasonable relates to the proposed changes to the block rate design. Because the Administrative Law Judge has recommended no changes to the block rate design, any additional changes directly related to Applicant's block rate proposal should not be made.

vi. Large Power Interruptible Product

[1033] *Id.*
[1034] *Id.*
[1035] ECC Initial Br. at 21-22 (Sept. 12, 2017) (eDocket No. 20179-135453-01); Ex. 200 at 44-47 (Marshall Direct); Ex. 202 at 35-37 (Marshall Surrebuttal).
[1036] ECC Initial Br. at 21-23 (Sept. 12, 2017) (eDocket No. 20179-135453-01).
[1037] *Id.*
[1038] *Id.*

Applicant did not propose changes to its Large Power Interruptible Service Rider.[1039] Several changes were, however, proposed by LPI.[1040] This was because of under-utilization of Applicant's current demand response products, and because "LPI believes there is substantial untapped demand response potential on the Company's system[.]"[1041]

Applicant is "amendable to working with the LPI group on expanding its demand response products[.]"[1042] However, the burden in this case is on Applicant to show its proposals are just and reasonable.[1043] Because Applicant has not proposed a change in its Large Power Interruptible Product, there is no basis to further consider this topic here. Applicant and LPI are encouraged to discuss the issue and address it with the PUC in the appropriate forum.

vii. Large Power Incremental Production Rider

Applicant's Position

Applicant proposes to increase its Large Power Incremental Production Service (IPS) energy usage limit to 120 percent of each large power customer's IPS threshold, from the current 110 percent limit.[1044] This will, according to Applicant, allow large power customers access to more incrementally priced or market-based energy.[1045] It will also double the quantity of demand and associated energy that can be taken without incurring demand charges.[1046]

Applicant argues that this change will provide benefits to its customers and its system overall.[1047] According to Applicant, it will be able to reduce the amount of capacity that it maintains to serve peak load and the associated cost of that capacity.[1048] The proposed change will also reduce energy supply costs for non-large power customers because IPS is served with the highest cost energy on the system.[1049] Further, the cost of this energy is excluded from the firm supply used to determine the fuel clause cost for all firm retail sales.[1050] As a result, the average cost for firm energy supply is reduced.[1051]

Challenges to Applicant's Position

[1039] Applicant Initial Br. at 154 (Sept. 12, 2017) (eDocket No. 20179-135459-02).
[1040] *Id.* at 154-55; LPI Initial Br. at 38-42 (Sept. 12, 2017) (eDocket No. 20179-135470-02); Ex. 104 at 10-28 (Stephens Direct).
[1041] LPI Initial Br. at 40 (Sept. 12, 2017) (eDocket No. 20179-135470-02).
[1042] Applicant Initial Br. at 154 (Sept. 12, 2017) (eDocket No. 20179-135459-02).
[1043] Minn. Stat. §§ 216B.03, .16.
[1044] Ex. 82 at 71-72 (Podratz Direct); Ex. 86 at 35-37 (Podratz Rebuttal); Ex. 87 at 13-14 (Podratz Surrebuttal).
[1045] Ex. 82 at 71 (Podratz Direct); Ex. 86 at 35 (Podratz Rebuttal).
[1046] Ex. 82 at 72 (Podratz Direct).
[1047] Applicant Initial Br. at 157 (Sept. 12, 2017) (eDocket No. 20179-135459-02).
[1048] Ex. 86 at 36 (Podratz Rebuttal).
[1049] *Id*.
[1050] *Id*.
[1051] *Id*.

OAG object's to Applicant's proposal to change the IPS Rider.[1052] OAG argues that while large power customers will benefit from this proposal, other customers will not receive meaningful benefits.[1053] According to OAG, the large power customers benefiting from the IPS will not be paying for a portion of the utility's fixed costs which are recovered through demand charges.[1054]

OAG argues that Applicant "has not demonstrated that providing its [l]arge [p]ower customers with these higher discounts is needed."[1055] According to OAG, Applicant must demonstrate it "needs additional curtailable load, or that the addition of this curtailable load will offset the need for another resource."[1056] Finally, OAG argues that even if it is true that this change will reduce energy costs for Applicant and other customers, Applicant has not shown that these lower costs will offset the lost revenue from lowered demand charges.[1057] Thus, according to OAG, the proposed change is not reasonable.

Analysis

Ensuring some of Applicant's large power customers have access to a supply of energy that assists their competitiveness in the international marketplace is one of the state's current policies.[1058] Applicant's proposal furthers that policy. The proposal will permit these customers to take advantage of lower priced electricity. Taconite producers will be able to respond to short-term opportunities to increase production without a correspondingly high electric cost.

There are also system benefits, which positively affect all customers. IPS is a curtailable product. As a result, the expansion of its use provides additional load curtailability on the electric grid. The impact of this is a reduction in the amount of capacity the utility must maintain to serve peak load and the associated cost of that capacity. In addition, this proposal reduces energy supply costs for many customers because IPS is served with the highest-cost energy on the system, and the cost of this energy is excluded from the firm supply used to determine the fuel clause cost for firm retail sales. As a result, the average cost for firm energy is reduced.

Conclusion

Applicant's proposed change to its IPS Rider is just and reasonable. The Administrative Law Judge recommends the PUC permit the change.

[1052] A Department witness, Michael Zajicek, testified that the PUC should reject the proposal. *See* Ex. 614 at 42-43 (Zajicek Direct). However, the Department did not argue this point in summation.
[1053] OAG Initial Br. at 152 (Sept. 12, 2017) (eDocket No. 20179-135457-02).
[1054] *Id.*; Ex. 509 at 100-101 (Nelson Direct).
[1055] OAG Initial Brief at 152 (Sept. 12, 2017) (eDocket No. 20179-135457-02).
[1056] *Id.*; Ex. 511 at 40 (Nelson Rebuttal).
[1057] OAG Initial Brief at 152 (Sept. 12, 2017) (eDocket No. 20179-135457-02); Ex. 86 at 36 (Podratz Rebuttal).
[1058] Minn. Stat. § 216B.1696, subd. 2.

viii. Large Light and Power Time-of-Use Rider

According to Applicant, no customers are currently taking advantage of its existing Large Light and Power (LLP) Time-of-Use (TOU) rider.[1059] In order to incentivize LLP customers to use the rider, Applicant proposes to increase the on-peak rate by approximately the same percent as the overall rate increase for the standard LLP service schedule.[1060] The off-peak demand charge would not change under Applicant's proposal.[1061]

Applicant argues that by increasing the differential between the on- and off-peak rates, LLP customers will be incentivized to research the benefits of shifting their power usage to off-peak times and take advantage of the savings.[1062] If customers take advantage of the lower off-peak rates, they will positively impact energy usage patterns by consuming more power during low-cost periods and less power during high-cost periods. Further, according to Applicant, this change will serve as a pilot to collect data and help it determine how best to roll out a broader LLP TOU rate.[1063]

While witnesses for two parties, Mr. Nelson for OAG and Mr. Zajicek for the Department, expressed disapproval of Applicant's proposal for the LLP TOU rider, neither party pursued this in its closing briefs. Thus, OAG and the Department have dropped any opposition to the proposal.

Applicant's proposal is reasonably designed to incentivize use of the LLP TOU rider, which no customer is currently using. If LLP customers take advantage of the rider, the on- and off-peak periods of usage will flatten out – a benefit to the overall electric system by making it more efficient. Thus, Applicant's proposed change is just and reasonable and it should be approved.

ix. Back-up Generation Rider

Applicant's Position

Applicant seeks tariff update approval for its new Back-up Generation Program (the Program). The Program was approved by the PUC in 2015.[1064] Customers participating in the Program work with the Applicant to cost-effectively obtain a utility grade generator with better emission performance than those typically used in a commercial setting.[1065] Customers will then be able to rely on the back-up generator to

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[1059] Ex. 82 at 66 (Podratz Direct).
[1060] *Id*. at 67.
[1061] *Id*.
[1062] *Id*.; Applicant Initial Br. at 159 (Sept. 12, 2017) (eDocket No. 20179-135459-02).
[1063] Applicant Initial Br. at 160 (Sept. 12, 2017) (eDocket No. 20179-135459-02); Ex. 86 at 34 (Podratz Rebuttal).
[1064] Ex. 71 at 11 (Pierce Rebuttal); *In re Minn. Power's Application for Approval of its 2015-2019 Res. Plan,* MPUC Docket No. E015/RP-15-690, Integrated Resource Plan at Appendices J and K (Sept. 1, 2015).
[1065] Ex. 67 at 39-40 (Pierce Direct).

avoid extended service interruptions during outage conditions.[1066] In addition, Applicant benefits when these generation units are operated to meet system peak load, which supports the reliability of the broader electric grid.[1067]

The Program is designed to serve customers with a load profile of 250 kW to 1 MW.[1068] However, because the Program provides benefit to the system as a whole during peak periods, the Program benefits all customers, according to Applicant.[1069] As a result, Applicant argues, the costs of the Program should be allocated to all customers.[1070]

Challenges to Applicant's Position

The Department argues that the proposed tariff update for the Program is not compliant with Minnesota Statute section 216B.03 because it is unreasonably prejudicial to non-participating customers.[1071] According to the Department, the costs of the Program borne by non-participating customers have not been shown to correspond to the benefits those customers would receive.[1072] No attempt was made by the Applicant, argues the Department, to estimate the benefits to non-participating customers or to compare those benefits to the costs Applicant proposes to allocate to them.[1073] Further, the Department argues that the reasonable number for calculating system benefits in the proposed Program rate is $0.[1074]

OAG also opposes the Program tariff. According to OAG, Applicant has not demonstrated it needs an additional 10 MW of capacity at peak-load times.[1075] Even if this was shown, according to OAG, Applicant has not shown the Program is the most cost-effective way to do it.[1076] Further, according to OAG, the Program gives Applicant an unfair competitive advantage over third-party providers of back-up generation.[1077] Finally, argues OAG, the Program could lead to the installation of up to 10 MW of diesel or other fossil fuel generators, in contradiction to the state's policy goal of reducing fossil fuel consumption.[1078]

Analysis & Conclusion

The PUC has already considered and approved the Program. What remains to be determined is whether Applicant's proposal to pay for it is just and reasonable. Assuming

[1066] *Id*.
[1067] *Id*.
[1068] Ex. 71 at 11 (Pierce Rebuttal).
[1069] *Id*. at 9, 11; Applicant Initial Br. at 162 (Sept. 12, 2017) (eDocket No. 20179-135459-02).
[1070] Applicant Initial Br. at 162 (Sept. 12, 2017) (eDocket No. 20179-135459-02).
[1071] Department Initial Br. at 223, 226-27 (Sept. 12, 2017) (eDocket No. 20179-135469-01); Ex. 612 at 48-54 (Collins Surrebuttal).
[1072] Ex. 610 at 42-44, 46-47 (Collins Direct).
[1073] Department Initial Br. at 226-27 (Sept. 12, 2017) (eDocket No. 20179-135469-01).
[1074] Ex. 612 at 51 (Collins Surrebuttal).
[1075] OAG Initial Br. at 155 (Sept. 12, 2017) (eDocket No. 20179-135457-02).
[1076] *Id*.
[1077] *Id*.
[1078] *Id*.; *see also* Minn. Stat. § 216C.05, subd. 2 (2016).

the underlying facts are true, Applicant has demonstrated its proposed tariff update to fund the Back-up Generation Program is just and reasonable.

An adequate, efficient, and reasonable supply of electricity is a significant component of Minnesota's energy policy.[1079] It is not incumbent upon Applicant to demonstrate that it must have this back-up generation program. Indeed, the PUC already approved the Program. Applicant has convincingly argued that the benefits of the Program will be shared by both the participant ratepayers and non-participant ratepayers. In fact, given the rarity of power outages – a condition for which the Program directly benefits Program participants – it is likely the primary benefit will be to the grid as a whole when the Program's generators are used to support the system during peak energy usage. This circumstance benefits all customers by ensuring reliability and helping to eliminate the need for a more expensive solution, such as a new large generation plant. Thus, it is recommended Applicant's proposal for the tariff update for the Program be approved.

x. Green Pricing Program

Applicant's Position

Applicant proposes to modify its rider for Residential/General Electric Service Renewable Energy to develop an optional Green Pricing Program, consistent with Minn. Stat. § 216B.169 .[1080] Under Applicant's proposal, customers can choose to get between 25 percent and 100 percent of their electricity from renewable energy.[1081]

To cover the costs of the Green Pricing Program, Applicant wants to charge customers who opt to participate a certification fee, an administration fee, and the cost of the renewable energy purchased, on top of the cost of fuel for its traditional generation plants.[1082] According to Applicant, it is only recovering the incremental cost of the renewable energy, and so the full cost of fuel under the FCA rider should be permitted to be recovered from participants.[1083]

Challenges to Applicant's Position

CEO supports approval of the Green Pricing Program, but objects to requiring customers who opt in to pay the FCA. CEO argues that including this provision in the Green Pricing Program violates Minn. Stat. § 216B.169, subd. 2(b), because participants would be charged for fuel. Fuel is a cost attributable to Applicant's "mix of renewable and

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[1079] Minn. Stat. § 216B.16, subd. 6.
[1080] Ex. 76 at 1-19 (Koecher Direct).
[1081] *Id*. at 11-12.
[1082] Applicant Initial Br. at 165 (Sept. 12, 2017) (eDocket No. 20179-135459-02); Ex. 76 at 16 (Koecher Direct); Ex. 77 at 9 (Koecher Rebuttal).
[1083] Applicant Reply Br. at 30 (Sept. 28, 2017) (eDocket No. 20179-135885-01); Ex. 77 at 9 (Koecher Rebuttal).

nonrenewable energy sources" and this cost is not incurred when a customer opts for electricity generated by renewable resources.[1084]

According to CEO, Applicant will incur fewer operating and fuel costs at its existing thermal plants, or incur less expense in its energy procurements through its other power purchase agreements.[1085] CEO argues that Applicant would be overcharging customers who participate in the Green Pricing Program if those customers do not see a benefit in taking advantage of renewable energy sources because they are still paying the full existing fuel prices for the power sources they are opting out of.[1086] CEO argues that in 2002 the PUC prohibited another utility from taking the approach Applicant proposes and instead required renewable energy customers to only pay a pro-rata share of the fossil-fuel cost adjustments.[1087]

Analysis

Minnesota law encourages the use of renewable energy and permits utilities recover some of the cost for electricity produced by renewables. Minn. Stat. § 216B.169, subd. 2(b) provides that when a utility offers its customers an option to purchase renewable energy, the rates charged:

> must be calculated using the utility's cost of acquiring the energy for the customer and must:
>
> (1) *reflect the difference between* the cost of generating or purchasing the additional renewable energy and the cost that would otherwise be attributed to the customer for the same amount of energy based on the utility's mix of renewable and nonrenewable energy sources[.] (Emphasis added.)

Applicant may offer a renewable energy program to its customers. However, the legislature only permits utilities to recover the incremental cost for renewable energy options. Had it wanted to permit utilities to recover the cost of fuel customers do not use, it would have said so. It did not. Thus, Applicant's proposal to add the total cost of fossil fuels not used by participating customers and the cost of the renewable energy they opt for violates Minn. Stat. § 216B.169. In addition, the proposal requires customers to pay for sources of energy they are not using.

Conclusion

The Administrative Law Judge concludes that Applicant's Green Pricing Program is just and reasonable with one exception. The proposed Green Pricing Program aligns with state policy on promoting the use of renewable energy sources. However,

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1084 CEO Initial Br. at 18 (Sept. 12, 2017) (eDocket No. 20179-135454-01); Minn. Stat. § 216B.169, subd. 2(b)(1).
1085 CEO Initial Br. at 19 (Sept. 12, 2017) (eDocket No. 20179-135454-01).
1086 CEO Initial Br. at 19 (Sept. 12, 2017) (eDocket No. 20179-135454-01).
1087 CEO Initial Br. at 19-20 (Sept. 12, 2017) (eDocket No. 20179-135454-01).

participating customers should only be charged at a pro-rata share of the energy obtained from traditional sources. It is not just and reasonable to permit Applicant to violate the statute on the recovery of renewable energy costs, or to permit Applicant to recover from customers the cost of fuel they do not use. Thus, it is recommended that Applicant be permitted to implement the Green Pricing Program with the requirement that participating customers are only charged their pro-rata share of the energy they use that is obtained from non-renewable sources.

xi. Reconnect Pilot

Applicant's Position

Applicant proposes to begin a new pilot program which permits the reconnection of electric service remotely for customers who have been disconnected as a result of non-payment.[1088] Remote reconnection is possible using advanced metering infrastructure (AMI) that has already been installed.[1089]

Applicant proposes a pilot program because not all customers have AMI yet. Applicant seeks to learn about the customer experience resulting from the program, as well as the program's scalability and effectiveness, operational savings, technology and administrative costs, and safety benefits.[1090] The fee for reconnection under the pilot would be $20 at all times. Currently, the $20 reconnect fee rises to $100 after business hours and on weekends and holidays.[1091] Remote reconnection could also happen more quickly due to not needing to send staff to the reconnection location. Reconnection and the safety of the customer will be confirmed via telephone.[1092]

The pilot would be offered to approximately 200 residential customers throughout Applicant's service territory, and mostly within Duluth and Cloquet.[1093] The cost to configure installed AMI with reconnect capability is nearly 42 percent per meter, and so the pilot is focused on customers who likely would experience disconnection and require reconnection.[1094] As the technology improves and incremental costs decrease, the offering of this capability will likely expand, according to Applicant.[1095]

The Department supports the pilot program, and also recommends Applicant be required to report on achieved savings in a compliance filing.[1096] Applicant agrees to provide compliance filing and suggests this be done as part of annual Safety, Reliability and Service Quality Standards (SRSQ) reporting.[1097]

1088 Ex. 76 at 19 (Koecher Direct).
1089 *Id.* at 19-21.
1090 *Id.* at 21.
1091 *Id.* at 20.
1092 *Id.* at 22.
1093 *Id.* at 20.
1094 *Id.* at 20-21.
1095 *Id.* at 21.
1096 Ex. 614 at 7-8 (Zajicek Direct).
1097 Ex. 77 at 10 (Koecher Rebuttal); Ex. 614 at 8 (Zajicek Direct).

Challenges to Applicant's Position

ECC argues the pilot for remote reconnection should be rejected. In addition to a general concern that the pilot has "the potential for undermining consumer protections," the ECC offers four reasons. First, ECC argues the pilot program discriminates against low-income and rental households.[1098] Second, ECC argues that the pilot does not resolve safety concerns because the reconnection would not be accompanied by a physical visit to the location.[1099] Third, ECC argues that the pilot should not be approved because Applicant is also testing remote disconnections and such disconnection must occur before a remote reconnection.[1100] Finally, ECC argues that the pilot will not result in faster reconnections.[1101]

Analysis

Applicant has provided sufficient evidence and explanation to support its proposed pilot as just and reasonable. ECC's arguments do little to convince the Administrative Law Judge that Applicant has not made the requisite showing. The argument that the pilot is discriminatory toward low-income and rental customers is surprising. Applicant is prudently and deliberately selecting customers because they have a higher likelihood of being disconnected from service due to non-payment. It would make little sense to test a program on a different group of customers, or all residential customers, given the cost and on the off chance some of them might to disconnected due to non-payment. In addition, when low-income customers are disconnected and then get their finances in order sufficient to resume electric service, the pilot benefits them directly by ensuring they may be reconnected at any time at the same low price as Applicant charges during regular business hours.

ECC's arguments about safety, likewise, are unconvincing. Remote reconnection can happen when the customer initiates it through contact with the utility. Since utility staff and the customer will be on the phone together when electric service is resumed, there appears to be no safety issue.

ECC's other arguments are also unavailing. First, whether or not Applicant is or has tested remote disconnections is not the issue before the PUC. The issue is remote reconnection. Applicant has shown that it complies with legal requirements for disconnections. Even if remote reconnections require remote disconnections, it must be presumed absent evidence to the contrary that the remote disconnections are done in accordance with law.[1102]

Second, one of the reasons for the pilot is to assess whether reconnection can happen more quickly than at present. Because this is a test, it is not reasonable to expect or require Applicant to ensure disconnected customers have power restored in a shorter

[1098] ECC Initial Br. at 14 (Sept. 12, 2017) (eDocket No. 20179-135453-01).
[1099] *Id.* at 14-16.
[1100] *Id.* at 16-17.
[1101] *Id.* at 17.
[1102] *See* Ex. 77 at 13 (Koecher Rebuttal).

period of time. Indeed, becoming disconnected and reconnected are also in the hands of each customer. If a customer who was disconnected for non-payment fails to take action to become reconnected, there would be no reason to reconnect that customer by any means. Further, once the customer initiates the reconnection process, not having to send a utility worker to the customer to perform the reconnection is likely to reduce the amount of time and money necessary for reconnection.

Conclusion

Applicant has shown its remote reconnection pilot is just and reasonable. The Administrative Law Judge recommends the pilot be approved, including the requirement for reporting in the annual SRSQ filing.

xii. GRID Pilot

Applicant's Position

Applicant proposes a GRID Pilot and related rider that will serve as a research and development mechanism for working toward grid modernization in an effective manner.[1103] According to Applicant, the Grid Pilot proposal is a project to enable Applicant to demonstrate new grid modernization technologies and innovative projects in collaboration with customers and communities. The goal is to test the abilities, costs, and benefits of these new technologies.[1104] Applicant wants to use a rider designed to enhance transparency and provide flexibility necessary to advancing grid modernization.[1105]

Applicant wants to include a stakeholder advisory committee and governance model to oversee the project selection process, project review, and status updates.[1106] The committee would also support annual compliance reporting, including an update on funding status, project progress, and evaluative findings.[1107] The committee and governance structure would be modeled after the U.S. Department of Energy's Smart Grid Investment Grant (SGIG).[1108] It would include a detailed project execution plan, metrics and benefits reporting, and financial transparency.[1109] Stakeholders will come from the community, the Department and/or OAG, technical experts, and impartial industry experts.[1110]

Applicant also seeks to maintain flexibility with the GRID Pilot so that it can respond quickly and effectively to emerging technologies and changes in the marketplace.[1111]

[1103] Ex. 76 at 23 (Koecher Direct).
[1104] *Id.* at 23-28; Ex. 77 at 15-22 (Koecher Rebuttal).
[1105] Applicant Initial Br. at 169 (Sept. 12, 2017) (eDocket No. 20179-135459-02).
[1106] Ex, 76 at 27-28 (Koecher Direct).
[1107] Ex. 77 at 18 (Koecher Rebuttal).
[1108] Ex. 76 at 27 (Koecher Direct).
[1109] *Id*.
[1110] *Id*.; Ex. 77 at 20-21 (Koecher Rebuttal).
[1111] Applicant Initial Br. at 169-70 (Sept. 12, 2017) (eDocket No. 20179-135459-02); Ex. 76 at 23-24 (Koecher Direct).

Minimizing the regulatory process in employing the GRID Pilot will be consistent with PUC staff proposals for effectively grappling with grid modernization.[1112] Thus, according to Applicant, PUC authority over final project selection would not be appropriate because of the lag time involved for PUC review.[1113]

Applicant proposes $2.7 million be raised annually through the rider. It proposes to incorporate the rider on customers' bills in the current Resource Adjustment line. Applicant is open to listing the GRID Pilot rider as a separate line item.[1114] Residential customers can expect to pay, on average, $7.43 per year, or $.62 per month, for the GRID Pilot. Further, because Applicant proposes to include only distribution-level customers in the GRID Pilot and because it involves distribution-level technology, Applicant will exclude large power customers served at the transmission level.[1115] Finally, recovery of costs for the GRID Pilot would not come from low-income (LIHEAP-eligible) customers even though those customers would be included in the Pilot.[1116]

Challenges to Applicant's Position

OAG, ECC and CUB all challenge Applicant's proposed GRID Pilot to different degrees.[1117] OAG believes the proposal is not developed well enough. First, according to OAG, the identification of categories of potential projects versus the identification of specific projects is "concerning" where Applicant intends to collect $2.7 million per year for these unidentified projects.[1118] Second, OAG objects to Applicant keeping the authority to determine which experimental projects will be deployed to itself. Applicant refuses to permit the proposed stakeholder committee to make those determinations.[1119] Finally, OAG objects to the exclusion of large power customers from the rider.[1120] According to OAG, Applicant incorrectly focuses on the distribution-level technology, rather than the benefits to all customers the technology may produce.[1121]

ECC also argues that the proposed GRID Pilot be rejected. ECC argues that the proposal is "ill-defined" and so should not be granted up-front cost recovery.[1122] ECC also argues that the proposal should be rejected because it is not designed to benefit low-income customers.[1123] Integrating and accommodating distributed energy resources (DER) is of no benefit to low-income customers because those customers are the least likely to invest in DER.[1124] Further, according to ECC, because Applicant relies on third

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[1112] Applicant Initial Br. at 70 (Sept. 12, 2017) (eDocket No. 20179-135459-02).
[1113] Ex. 77 at 20 (Koecher Rebuttal).
[1114] *Id*.
[1115] *Id*.
[1116] *Id*.
[1117] Department witness Michael Zajicek recommended that the GRID Pilot proposal be denied due to lack of definition for specific projects. Ex. 614 at 9 (Zajicek Direct). The Department did not argue this point in summation, however. Any objection the Department may have is deemed waived and not addressed here.
[1118] OAG Initial Br. at 156 (Sept. 12, 2017) (eDocket No. 20179-135457-02).
[1119] *Id.* at 156-57
[1120] *Id.* at 157.
[1121] *Id.*
[1122] ECC Initial Brief at 11 (Sept. 12, 2017) (eDocket No. 20179-135453-01).
[1123] *Id.* at 11-12.
[1124] *Id.* at 11.

parties to identify low-income customers, Applicant is not likely to ensure these customers will be identified and exempted from the proposed rider.[1125]

CUB also believes the GRID Pilot proposal requires additional definition before approval is given.[1126] CUB argues that further specification is required of the stakeholder committee. Who will be on the committee, its role, and how it will function, all need to be defined.[1127] CUB also believes that Applicant should identify specific projects as well as the criteria for selection and implementation.[1128] CUB also argues that Applicant should not be making the final determinations on the selection of specific projects.[1129] The process must be designed, according to CUB, to ensure small programs that primarily benefit customers are not overlooked for projects that require significant capital investments which primarily benefit shareholders.[1130]

Because CUB supports the general idea of grid modernization, it proposed several solutions to its concerns that, if adopted, would change its position to one of support. CUB argues that the PUC should pre-approve projects following stakeholder review.[1131] CUB also argues that the role of the advisory committee be strengthened and formalized, with committee members appointed by the PUC.[1132] Members of the committee should come from: OAG; the Department; an environmental advocacy organization; a consumer advocacy organization; a low-income customer advocacy organization; a business organization or trade group; a local unit of government; a tribal government; the PUC; Applicant; and any other representative the PUC may appoint.[1133] Further, CUB argues the committee should be provided staff and two percent of the funds for developing, presenting, and evaluating potential projects.[1134]

Analysis

It is self-evident that grid modernization is important. As with any mechanical infrastructure, the grid wears out and new technology is developed that can improve the function and efficiency of the asset. Technological changes are rapid and it is not self-evident what solutions to improve Applicant's grid will work because it is unique in the industry. Thus, the general proposal to permit Applicant to test out current and future technologies in various ways makes sense. To not do anything will negatively impact both Applicant and its customers as new grid technologies will not be deployed or deployed only slowly.[1135]

1125 *Id.* at 12.
1126 CUB Initial Br. at 2 (Sept. 12, 2017) (eDocket No. 20179-135439-01); Ex. 451 at 2 (Cohen Direct).
1127 CUB Initial Br. at 2 (Sept. 12, 2017) (eDocket No. 20179-135439-01); Ex. 451 at 3 (Cohen Direct).
1128 CUB Initial Br. at 2 (Sept. 12, 2017) (eDocket No. 20179-135439-01); Ex. 451 at 6-7, 9-10 (Cohen Direct).
1129 CUB Initial Br. at 2, 7 (Sept. 12, 2017) (eDocket No. 20179-135439-01); Ex. 451 at 7, 9 (Cohen Direct).
1130 CUB Initial Br. at 3 (Sept. 12, 2017) (eDocket No. 20179-135439-01); Ex. 451 at 7-8 (Cohen Direct).
1131 CUB Initial Br. at 2, 7 (Sept. 12, 2017) (eDocket No. 20179-135439-01); Ex. 451 at 7, 9 (Cohen Direct).
1132 CUB Initial Br. at 9 (Sept. 12, 2017) (eDocket No. 20179-135439-01); Ex. 451 at 8 (Cohen Direct).
1133 CUB Initial Br. at 9 (Sept. 12, 2017) (eDocket No. 20179-135439-01); Ex. 451 at 8-9 (Cohen Direct).
1134 CUB Initial Br. at 10 (Sept. 12, 2017) (eDocket No. 20179-135439-01); Ex. 451 at 3, 14 (Cohen Direct).
1135 Consider, for example, the state of the electrical grid in Puerto Rico (reports are that it was poor) before the recent hurricane, and the impact that the storm had on the delivery of safe and reliable energy to the

Yet, critics are correct that Applicant's proposal, in its detail, does not ensure a just and reasonable use of funds for the intended purpose. Fortunately, solutions to correct the failings have been offered. These solutions, however, must be independently considered and weighed in light of the rights and interests of Applicant, shareholders, customers, and state policy. Who benefits, who pays, and who decides, are all questions to drive an appropriate response as to what is just and reasonable.

The objections to the collection of $2.7 million from customers without more specifics about how it will be spent are valid. So is Applicant's desire to be able to move relatively quickly on testing potential new technology. Purely economic incentives should not solely drive project proposals and decisions. Those incentives may not always be in alignment with the benefits customers need or want and with state policy. One of the means to address and balance these concerns is to require both customers and Applicant to contribute the funds necessary. This ensures Applicant has, as is colloquially said, skin in the game. The argument that large power customers should be included for the purpose of raising the funds has merit since they will be beneficiaries of grid improvements. However, they are largely subject to another legitimate factor, their trade-exposed status. Thus, because state policy is to ensure the viability of the companies who are large power customers, it is reasonable for Applicant to exclude them from the rider funding the GRID Pilot.

Applicant's proposal to make the decisions about which GRID Pilot projects proceed is another close call. While the arguments about Applicant's motivation for types of projects are valid, in the end, Applicant is accountable to the PUC. Applicant's argument for being able to make decisions relatively quickly has merit, given the rapidity of technological change and PUC staff recommendations to avoid regulatory lag. Other concerns can be addressed through additional improvements, such as requiring Applicant to contribute at least half of the funds for the Pilot, and a more defined structure to the stakeholder committee. Ultimately, Applicant will have to report to the PUC about its projects under the GRID Pilot and it will be held accountable. Not based on whether projects succeed or fail, because some will fail, but based on whether the projects are just and reasonable in light of state policy goals. Pre-approval is simply unnecessary and may stymie the risk-taking necessary for productive research and development.

ECC's arguments against the proposal based on concerns about low-income customers are unavailing. Obviously, grid modernization is a benefit to all customers. Applicant is proposing that no part of the cost be collected from low-income customers. This is logical for the same reason not collecting the cost from large power customers is logical, and it is in conformity with state policy. Finally, the argument that Applicant is not likely to identify low-income customers to exempt them from the rider is speculation.

Applicant's proposal to rely on the model of the SGIG requires additional detail to ensure all other components of the GRID Pilot and rider are just and reasonable. CUB

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territory. The Administrative Law Judge takes judicial notice that the grid in Puerto Rico was nearly wiped out and now faces a long process of reconstruction.

has provided a level of detail that is useful for building these necessary components. While Applicant's proposals to make the final determination about who sits on the stakeholder committee and which projects it will proceed on are reasonable, Applicant's stakeholder committee proposal should be adjusted in accordance with the recommendations of CUB. This will ensure the projects that are ultimately selected will be properly vetted and, if there is a loud objection to a particular project, the PUC will be able to readily review the project without simply relying on the evidence provided solely by Applicant.

Conclusion

Applicant's proposed Grid Pilot and related rider should be approved with adjustments. Because the potential benefits and risks of the research and development will be borne by both Applicant and customers, the proposal should be amended to reflect this and to ensure accountability, while still meeting the flexibility Applicant argues is necessary. Applicant should be required to match every dollar raised by the rider up to the $2.7 million requested. Further, the stakeholder advisory committee should be more defined, to include a precise number of representatives from specifically identified groups or organizations, and not to exceed 12 to 15 people representing an equal number of groups or organizations.[1136] The recommendations provided by CUB should be relied on for further defining the committee and its functions. With these amendments, Applicant's proposal for the GRID Pilot project and the related rider will be just and reasonable.

xiii. Credit Card Fees

All forms of payment have a cost. Applicant's customers are only individually charged the cost of payment when they use a debit or credit card. The question of credit card fees was analyzed above under the issue concerning the appropriate test year rate base. Consistent with that analysis, it is recommended that Applicant be required to stop charging customers a fee for using a debit or credit card to make payments on their electric bill.

Rather than merely shifting the current transaction cost of debit and credit card use to all customers, Applicant should find a more efficient and cost-effective means for processing such payments. To incentivize further investigation by Applicant, it is recommended only $175,000 be permitted to be recovered under O&M expenses for Applicant, pending a full investigation into the most cost-effective means of paying for debit and credit card payments.

xiv. Annual Rate Review Mechanism (ARRM)

Applicant's Position

Applicant proposes to implement an annual rate review mechanism (ARRM) which would allow it to raise or reduce rates without proceeding through a rate case under Minn.

[1136] This number is on the generally accepted high side for participants in a functional group. It is high because of the varied interests and expertise of stakeholders.

Stat. § 216B.16. The ARRM is intended, according to Applicant, to be a fair and reasonable cost-based mechanism with benefits for both customers and shareholders.[1137] Applicant's primary concern is mitigating the risk of large power customers reducing or eliminating load due to the economic cycles those customers experience.[1138] Applicant understands the concept of the ARRM is new to Minnesota. If the ARRM is not approved as part of this rate-making case, Applicant would agree to have the issue examined and approved as part of a separate docket.[1139]

Challenges to Applicant's Position

The Department, OAG, and ECC all challenge Applicant's proposal for the ARRM. Walmart offered suggestions to ensure the proposal, if implemented, does not cause undue class subsidies.[1140] MCC supported the proposal with a suggested asymmetrical ROE comparison approach. Applicant rejected MCC's suggestion.[1141]

The Department, OAG, and ECC all argue that the ARRM proposal unreasonably shifts risk from shareholders to ratepayers.[1142] According to the Department, the volatility risk associated with costs and revenue is largely and appropriately borne by Applicant between rate cases.[1143] If ratepayers face potential rate increases of up to five percent per year, and there is no thorough rate case analysis to ensure all of Applicant's costs and revenues are reasonable, it is the ratepayers that are shouldering the risk of doing business, according to the Department.[1144] The Department argues the authorized ROE should be reduced if the proposal is permitted.[1145]

The Department argues that the ARRM eliminates Applicant's incentive to minimize costs.[1146] This is because, argues the Department, that but for a narrow range of plus or minus 50 basis points, excess profit is returned to the ratepayers and a short-term shortfall is extracted from ratepayer, regardless of the reason for the shortfall.[1147]

[1137] Applicant Initial Br. at 177 (Sept. 12, 2017) (eDocket No. 20179-135459-02); Ex. 86 at 44 (Podratz Rebuttal).
[1138] Applicant Initial Br. at 177 (Sept. 12, 2017) (eDocket No. 20179-135459-02); Ex. 82 at 94 (Podratz Direct), Ex. 86 at 49-51 (Podratz Rebuttal).
[1139] Applicant Initial Br. at 179-80 (Sept. 12, 2017) (eDocket No. 20179-135459-02); Ex. 86 at 44 (Podratz Rebuttal).
[1140] Walmart Initial Br. at 11-12 (Sept. 12, 2017) (eDocket No. 20179-135445-01); Ex. 151 at 19 (Chriss Direct).
[1141] Applicant Initial Br. at 179 (Sept. 12, 2017) (eDocket No. 20179-135459-02); Ex. 86 at 47 (Podratz Rebuttal); Ex. 300 (Blazar Direct) (Exhibit 300 has no page numbers).
[1142] Department Initial Br. at 160-63 (Sept. 12, 2017) (eDocket No. 20179-135469-01); Ex. 601 at 68 (Amit Direct); Ex. 606 at 36-37 (Amit Surrebuttal); OAG Initial Brief at 161-62 (Sept. 12, 2017) (eDocket No. 20179-135457-02); Ex. 501 at 58 (Lebens Direct); ECC Initial Brief at 10-11 (Sept. 12, 2017) (eDocket No. 20179-135453-01); Ex. 200 at 28 (Marshall Direct).
[1143] Department Initial Br. at 161 (Sept. 12, 2017) (eDocket No. 20179-135469-01); Ex. 601 at 68-69 (Amit Direct).
[1144] Department Initial Br. at 161 (Sept. 12, 2017) (eDocket No. 20179-135469-01); Ex. 601 at 68-69 (Amit Direct).
[1145] Department Initial Br. at 163 (Sept. 12, 2017) (eDocket No. 20179-135469-01).
[1146] *Id.* at 162; Ex. 601 at 68 (Amit Direct).
[1147] Department Initial Br. at 162 (Sept. 12, 2017) (eDocket No. 20179-135469-01); Ex. 601 at 68-69 (Amit Direct).

OAG argues the ARRM lacks performance metrics to ensure Applicant's incentives are aligned with ratepayers.[1148] According to OAG, the proposed three percent cap on O&M increases does not sufficiently protect ratepayers, and any revenue increase under a proposal like this should be tied to specific performance metrics.[1149]

OAG and ECC argue the ARRM is a significant regulatory change which should be rejected because there are other legal means to address Applicant's concerns, such as using a multi-year rate plan or decoupling.[1150] OAG also argues the regulatory burden of implementing the ARRM would be excessive.[1151] The additional annual reports, argues OAG, would require extensive analysis similar to what occurs in a traditional case but on an annual basis.[1152]

Analysis

Applicant has not shown that its proposed ARRM is just and reasonable. The current rate structure places the risk of doing business on Applicant and its shareholders. Of course, this is a regulated business as a result of the natural monopoly of centralized electric production and distribution, and so that risk is managed by the PUC in accordance with state policy. Applicant cites to no state policy supporting this novel mechanism for managing the utility's risk.

There is further doubt as to the reasonableness of the proposal because of the potential for ratepayers to see a fifteen percent increase in rates over a three year period following the rate increase the PUC may permit as a result of the pending proceeding. It is not reasonable to place this risk on ratepayers given the magnitude and speed of the possible increases. While such increases could be possible if Applicant felt, in each of those years that it was necessary to maintain electric service and a fair return on investment, the Applicant would necessarily proceed through a vigorous review process. This regulatory burden may be altered using one of the alternative mechanisms currently available in state law: decoupling and a multi-year rate plan.[1153]

Conclusion

Applicant has not shown the ARRM is just and reasonable. The shift in the risk from the utility and its shareholders to customers is not consistent with any current state policy. Thus, there are no modifications to the proposal which, at this time, warrant further review or consideration. It is recommended the proposed ARRM not be permitted.

[1148] OAG Initial Br. at 161 (Sept. 12, 2017) (eDocket No. 20179-135457-02); Ex. 501 at 57-58 (Lebens Direct).
[1149] Ex. 501 at 58 (Lebens Direct).
[1150] OAG Initial Brief at 161 (Sept. 12, 2017) (eDocket No. 20179-135457-02); Ex. 501 at 57-59 (Lebens Direct); ECC Initial Brief at 11 (Sept. 12, 2017) (eDocket No. 20179-135453-01).
[1151] OAG Initial Brief at 161 (Sept. 12, 2017) (eDocket No. 20179-135457-02).
[1152] *Id.*; Ex. 501 at 58 (Lebens Direct).
[1153] Minn. Stat. §§ 216B.03, .16, subd. 19, .2412 (2016).

xv. Decoupling

Applicant did not propose a revenue decoupling mechanism. One party, CEO, made this proposal. Because the burden of proof is on Applicant to show its proposal is just and reasonable, it is not appropriate to consider another party's proposal where that proposal is not tied to an alternative for a proposal made by Applicant that the party has sought to show does not meet Applicant's burden. In other words, it is not Applicant's duty to prove or disprove another party's proposal when that proposal is not an alternative to a proposal the Applicant made and the party has attempted to discount. Thus, the CEO proposal for decoupling is not analyzed here.

It is recommended no decoupling program be required to be developed or implemented at this time.

V. EFFECT OF STANDARD TARIFFS, ESAs, AND THE EITE CREDIT ON EXPECTED REVENUES FROM INDUSTRIAL CUSTOMERS

A. U.S. STEEL ESA

Minnesota Power and U. S. Steel reached an agreement on a proposed Amended and Restated Electric Service Agreement (2016 ESA) that defines the terms under which Minnesota Power provides service to U. S. Steel's Minnesota Taconite (Minntac) and Keewatin Taconite (Keetac) facilities.[1154] In December 2016 the PUC approved the 2016 ESA with the exception of one provision, a credit applicable only when both Minntac and Keetac are operating (the Provision).[1155] The PUC requested that additional information be provided in this proceeding to determine whether the Provision is in the public interest.[1156]

Applicant argues that the Provision is in the public interest because it is designed to incentivize increased operating levels at U. S. Steel's two facilities.[1157] According to Applicant, incentivizing increased production levels at both facilities provides a benefit to all Minnesota Power's customers in that it allows fixed costs to be spread over increased energy sales, results in lower rates, and provides an economic boost to the region.[1158]

LPI and the Department agree that the Provision is highly effective and that it was an important incentive for re-opening the Keetac facility.[1159]The Department asserts that the Provision likely helped avoid a permanent shutdown of Keetac.[1160]

[1154] Ex. 62 at 1 (Perala Supplemental Direct).
[1155] *Id.*; *see In re Pet. by Minn. Power for Approval of an Amended and Restated and Elec. Serv. Agreement between United States Steel Corp. and Minn. Power*, MPUC Docket No. E015/M-16-836, Order Approving in Part Proposed Electric Service Agreement, Referring Matter to Rate Case, and Closing Docket (Dec. 29, 2016).
[1156] Ex. 62 at 1 (Perala Supplemental Direct).
[1157] *See id*.
[1158] *Id.* at 9.
[1159] Ex. 109 at 3-4 (Sutherland Rebuttal); Ex. 609 at 9 (Rakow Surrebuttal).
[1160] Ex. 609 at 9 (Rakow Surrebuttal).

As a result, the Department, LPI, and Applicant recommend that the PUC approve the proposed Provision in the ESA.[1161] The Provision is in the public interest and the Administrative Law Judge agrees it should be approved.

B. EITE CREDIT

Key features of the PUC's decision-making in Docket 16-564 regarding sales to energy-intensive, trade-exposed (EITE) customers, impacts the calculation of Applicant's sales revenues in this proceeding.[1162] In 2015, the Minnesota Legislature enacted Minn. Stat. § 216B.1696 (2016), a statute that authorized the provision of discounted electricity rates to EITE businesses. The statute declared that it is the policy of the state of Minnesota to ensure competitive electric rates for EITE firms. To that end, it directed the PUC to approve EITE rate proposals "upon a finding of net benefit to the utility or the state," notwithstanding certain other ratemaking provisions of Chapter 216B.[1163] Under Minn. Stat. § 216B.1696, if an EITE rate is approved, the PUC must allow revenue reductions (or increases) to be passed on to the utility's remaining non-EITE retail customers, with the exception of low-income customers who participate in the Low Income Home Energy Assistance Program.[1164]

On June 30, 2016, Applicant submitted a petition for: (1) approval of an EITE rate schedule that would provide specified customers a discount based upon each customer's site peak electric usage and total energy consumption; and (2) approval of an EITE Cost Recovery Rider.[1165] On December 21, 2016, the PUC approved Applicant's proposed set of discounted EITE rates as they applied to eleven customers. The PUC refrained from approving a cost recovery rider at that time, and instead ordered Applicant to file rate design proposals that detailed different alternatives for recovering the revenue deficiency that was associated with the discounts.[1166]

The maximum allowable Energy Charge Credit for the eleven customers was set at $19.2 million per year, based upon estimated full production rates of those customers. This amount represented a 5% decrease in the cost of electricity to those customers.[1167] Based upon expected operating rates, in 2016, Applicant estimated that the Energy

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[1161] Applicant Initial Br. at 33 (Sept. 12, 2017) (eDocket No. 20179-135459-02).
[1162] *See, e.g.,* Order Excluding Rider Revenue from 2016 Baseline Calculation and Setting Parameters to Identify Exempt Customers at 2 (Oct. 13, 2017) (eDocket No. 201710-136464-01) (Order Excluding Rider Revenue); Ex. 43 at 3 (Minke Surrebuttal); Ex. 632 at 34-35 (Lusti Surrebuttal).
[1163] Minn. Stat. § 216B.1696, subd. 2(a), (b) .
[1164] Minn. Stat. § 216B.1696, subd. 2(d) .
[1165] *See In re Minn. Power for a Competitive Rate for Energy-Intensive Trade-Exposed (EITE) Customers and an EITE Cost Recovery Rider,* MPUC Docket No. E015/M-16-564, Revised Petition of Minnesota Power (June 30, 2016).
[1166] *In re Minn. Power for a Competitive Rate for Energy-Intensive Trade-Exposed (EITE) Customers and an EITE Cost Recovery Rider,* Order Approving EITE Rate, Establishing Cost Recovery Proceeding, and Requiring Additional Filings, MPUC Docket No. 16-564 at 12 (Dec. 21, 2016).
[1167] *Id.* at 14.

Charge Credit would be approximately $13.5 million per year, a sum that represented an overall discount of 4.3%.[1168]

The PUC, in its December 30, 2016 Order Setting Interim Rates in this proceeding, approved Applicant's modified interim rate proposal and authorized a total annual interim rate increase of $34,732,113. This amount represented an upward adjustment of 5.6 percent to the base rate portion of customer bills. The rate is subject to downward adjustment if supplemental information filed by Applicant indicates that interim rates were set too high.[1169]

As noted above, in early 2017, U.S. Steel announced that its Keetac plant will resume operations. Based upon this additional information and recent completion of more detailed analyses, Applicant downwardly revised its interim rate revenue deficiency to $32,244,923 – an amount that was $2,487,190 lower than the $34,732,113 that was approved by the PUC in late December of 2016. As a result of this change, Applicant has proposed that the interim rate adjustment be reduced from 5.60 percent to 5.07 percent, on a prospective basis, effective May 1, 2017.[1170] As of early April 2017, the PUC was aware that U.S Steel was resuming operation and higher revenues associated with Applicant's sales of electricity to the Keetac plant would offset the effects of the EITE surcharge.[1171]

On April 20, 2017, the PUC entered an Order in the 16-564 Docket (EITE Order) requiring that net revenues received from "EITE-customers" be earmarked and refunded to the customers whose rates had funded the program's subsidies to trade-exposed businesses. The EITE Order states in relevant part:

> Minnesota Power shall refund revenue increases associated with the EITE rate schedule as proposed by the Office of the Attorney General on page 13 of its January 31, 2017 Comments in this docket, with the following additions/clarifications:
>
> a. The Company shall use the actual 2016 calendar-year EITE-customer revenue as the baseline for calculating the extent of any refundable increases;

[1168] *In re Minn. Power for a Competitive Rate for Energy-Intensive Trade-Exposed (EITE) Customers and an EITE Cost Recovery Rider,* MPUC Docket No. E015/M-16-564, Revised Petition of Minnesota Power at 2 (June 30, 2016).
[1169] *In re the Application of Minn. Power for Authority to Increase Rates for Electric Service in the State of Minnesota*, MPUC Docket No. E-015/GR-16-664, Order Setting Interim Rates at 2 (Dec. 30, 2016) (eDocket No. 201612-127718-01).
[1170] Ex. 84 at 6 (Podratz Supplemental Direct).
[1171] *See, e.g.,* Order Approving In Part Proposed Electric Service Agreement, Referring Matter To Rate Case, and Closing Docket at 3 (December 29, 2016) (eDocket No. 201612-127667-02); Ex. 632 at 36 (Lusti Surrebuttal).

b. The Company shall base the refund on net income increases [of 2017 and each subsequent year's EITE-customer revenue over 2016 EITE-customer revenue]….[1172]

While the EITE Order directed Applicant to use the "actual 2016 calendar-year EITE-customer revenue," as the baseline for any later EITE adjustment, Applicant is using a forward-looking 2017 test year in this rate case. To avoid counting the same revenues more than once, between the two dockets, the parties worked to determine the amount by which the 2017 EITE-customer net revenue exceeded the 2016 EITE-customer net revenue, back this amount out of Applicant's current rate case, and earmark the amounts for the refund that was ordered by the PUC in the 16-564 Docket.[1173]

On May 22, 2017, Applicant submitted a compliance filing in the 16-564 Docket, in which Applicant included its 2017 test-year forecast revenue from the Keetac plant.[1174] In June and July of 2017, several other parties maintained that Applicant's accounting of the added revenues did not comply with the methodology ordered by the PUC on April 20, 2017.[1175] Applicant and the Department agree as to the appropriate treatment in this rate case of the additional Keetac revenues for 2017. Specifically, both agree that the 2017 test-year sales revenue increases related to EITE customers must be removed from this rate case. Further, both parties agree to the amount to be removed from this rate case, as reflected in Column (g) of Schedule DVL-21 of Department witness Mr. Lusti's Surrebuttal Testimony.[1176]

Applicant's original request was an increase of $55.1 million per year. Applicant reduced this amount to $38.8 million for the test year following the announcement that the Keetac plant would resume operations. This is a net reduction of $16.3 million when all related factors are considered.[1177] Moving the accounting of Keetac's higher revenue (but not the related secondary adjustments) from the rate case to the EITE Docket (MPUC 16-564) increases the revenue requirements for this case back to $55.1 million. However, the $55.1 million figure is also increased by the effects of secondary related adjustments (such as an increase in taxes, reduction in asset based margins, etc.) that remain in the rate case.[1178] The total effect of the transfers between dockets is $18.1 million ($16.3 million of Applicant's Supplemental and $1.8 million in the Department sales adjustment). This calculation indicates a revenue surplus of $37,866 in the test year.[1179]

[1172] *In re Pet. for a Competitive Rate for Energy- Intensive Trade-Exposed (EITE) Customers and an EITE Cost Recovery Rider*, MPUC Docket No. E015/M-16-564, Order Authorizing Cost Recovery with Conditions at 12 (Apr. 20, 2017) (EITE Order).

[1173] *See id.* at 12; Ex. 43 at 1-8 (Minke Surrebuttal); Ex. 632 at 35-36 (Lusti Surrebuttal).

[1174] *See* Ex. 43 at 4-5 (Minke Surrebuttal).

[1175] *See* Order Excluding Rider Revenue at 4 (Oct. 13, 2017) (eDocket No. 201710-136464-01); Ex. 632 at 36-37 (Lusti Surrebuttal).

[1176] Ex. 632 at 38 (Lusti Surrebuttal); *see also* Applicant's Reply Brief at 29 (Sept. 28, 2017) (eDocket No. 20179-135885-01).

[1177] Order Excluding Rider Revenue at 3 (Oct. 13, 2017) (eDocket No. 201710-136464-01).

[1178] Ex. 620 at 4 (Shah Surrebuttal); Ex. 632 at 35-36 (Lusti Surrebuttal).

[1179] Ex. 632 at 38 (Lusti Surrebuttal).

As noted above, Applicant filed a request to reduce its interim rate proposal based upon revenues that the PUC later offset in the 16-564 Docket. While Applicant's proposal was reasonable at the time, it did not accurately forecast which of the two alternatives the PUC would later select for crediting the increased Keetac revenues. As a result, without a separate adjustment or credit, Applicant will be denied the opportunity to recover appropriate costs through interim rates.[1180]

Applicant likewise proposed that its initial filing on November 2, 2016, be used to determine the revenue deficiency in this Docket. It maintains that use of the figures would provide a clear, transparent baseline for later calculations and avoid double-counting the Keetac revenues in the two separate dockets.[1181]

On October 13, 2017, the PUC approved Applicant's proposal to exclude rider revenue from its 2016 baseline calculation.[1182] Additionally, the PUC directed Applicant to use the actual 2016 calendar-year EITE-customer revenue as the baseline for calculating the extent of any refund. As the PUC reasoned, failing to do so "would essentially deprive EITE customers of the full benefit of the EITE rate as intended by the statute."[1183]

LPI suggests that the impact of the EITE credit not be considered in this matter.[1184] However, the PUC provided direction to consider it, not a "suggest[ion]" as stated by LPI.[1185]

On November 2, 2017, Applicant filed a Petition for Reconsideration of the PUC's April 20 and October 13, 2017 Orders in the 16-564 Docket.[1186]

[1180] *See* Ex. 43 at 4 (Minke Surrebuttal).
[1181] *Id.* at 7.
[1182] Order Excluding Rider Revenue at 8 (Oct. 13, 2017) (eDocket No. 201710-136464-01).
[1183] *Id.* at 5, 8.
[1184] LPI Initial Br. at 37 (Sept. 12, 2017) (eDocket No. 20179-135470-02).
[1185] *Id*.
[1186] *In re Revised Pet. by Minn. Power for a Competitive Rate for Energy-Intensive Trade-Exposed (EITE) Customers and an EITE Cost Recovery Rider*, MPUC Docket No. E015/M-16-564, Minnesota Power's Petition For Reconsideration (Nov. 2, 2017).

The result of the increased electricity sales to EITE customers and the PUC's October 13, 2017 Order is that the EITE subsidy incurred by non-EITE customers appears to be non-existent at the current time. The idea behind the EITE credit is simple: reduce electricity costs for certain large power users and permit the utility to recover those lost revenues from other customers. The implementation of this idea through the EITE credit has been relatively complex. It is recommended the PUC pursue the intent of the EITE credit and debit through rate design, shifting rates closer to the cost of service. The result can be a decrease in cost for the EITE customers, which will be recovered through other customers. The extent of this shift and the impact on cost of the EITE customers should drive whether the PUC continues to use the EITE credit as a device to accomplish the legislature's goal with regard to supporting the EITE customers.

J. R. M.

OAH 5-2500-34078
MPUC E-015/GR-16-664

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in the State of Minnesota	**SUMMARY OF PUBLIC COMMENTS**

Public hearings were held at the following times and places:

June 19, 2017, at 2:00 p.m. at the Eveleth Civic Center[1187] in Eveleth, Minnesota;

June 19, 2017, at 6:30 p.m. at the Eveleth Civic Center[1188] in Eveleth, Minnesota;

June 20, 2017, at 2:00 p.m. at the Inn on Lake Superior[1189] in Duluth, Minnesota;

June 20, 2017, at 6:30 p.m. at the Inn on Lake Superior[1190] in Duluth, Minnesota;

June 21, 2017, at 6:30 p.m. at Itasca Community College[1191] in Grand Rapids, Minnesota; and

June 22, 2017, at 5:00 p.m. at the Morrison County Government Center[1192] in Little Falls, Minnesota.

The following persons appeared at the public hearings on behalf of the parties:

Dave McMillan, Executive Vice-President, Patrick Mullen, Senior Vice-President of External Affairs, and David Moeller, Senior Attorney, on behalf of Applicant;

[1187] Eveleth 2:00 p.m. Public Hearing Transcript (Eveleth 2:00 p.m. Tr.) (June 19, 2017).
[1188] Eveleth 6:30 p.m. Public Hearing Transcript (Eveleth 6:30 p.m. Tr.) (June 19, 2017).
[1189] Duluth 2:00 p.m. Public Hearing Transcript (Duluth 2:00 p.m. Tr.) (June 20, 2017).
[1190] Duluth 6:30 p.m. Public Hearing Transcript (Duluth 6:30 p.m. Tr. (June 20, 2017).
[1191] Grand Rapids Public Hearing Transcript (Grand Rapids Tr.) (June 21, 2017).
[1192] Little Falls Public Hearing Transcript (Little Falls Tr.) (June 22, 2017).

Kate O'Connell, Manager of Energy Planning and Advocacy, Samir Ouanes, Rate Analyst, Stephen Collins, Rate Analyst, and Michael Zajicek, Rate Analyst, on behalf of the Department;

Brian Lebens, Financial Analyst, Ryan Barlow, Assistant Attorney General, Ian Dobson, Assistant Attorney General, and Joseph Meyer, Assistant Attorney General, on behalf of OAG;

Seth Boffeli, Communications Director, Raashid Yassin, Program Specialist, and Kate Schaefers, President of AARP Minnesota, on behalf of AARP;

Andrew Moratzka and Emma Fazio, attorneys with Stoel Rives L.L.P., on behalf of LPI;

Hudson Kingston, attorney with Minnesota Center for Environmental Advocacy, and Jessica Tritsch, Senior Campaign Representative for Sierra Club, on behalf of CEO;

Annie Levenson-Falk, Executive Director, and Carmen Carruthers, Outreach Director, on behalf of CUB; and

Anne Thom, Consumer Affairs Supervisor, on behalf of the PUC.

In addition to the public hearings, the public was given the opportunity to submit written comments. The comment period closed on July 3, 2017.[1193] Written comments could be submitted several ways, including U.S. mail, email, and via the Commission's online platform SpeakUp.[1194] All submitted written comments were filed in the electronic docket for this matter.

I. SUMMARY OF PUBLIC COMMENTS

1. Over 500 written public comments were received by the deadline. In addition, over 60 individuals provided oral comments during the six public hearings.

2. All comments made during the public hearings or submitted in writing were fully considered. The following accurately summarizes the topics raised in the comments.

A. General Opposition to Rate Increases

[1193] Notice of Approval of Interim Rate and Public Hearings (Apr. 11, 2017) (eDocket No. 20174-130666-01).
[1194] *Id.*

3. The majority of public comments expressed concern regarding the size of the proposed rate increases. A large number of customers are opposed to any type of rate increase.[1195] Some individuals believe Minnesota Power should lower rates.[1196]

B. Fixed and Low Income Groups

4. Many individuals expressed concern about the burden on low and fixed income groups due to increased rates.[1197]

1195 Comment by Nancy Platzer (Jan. 23, 2017) (eDocket No. 20173-130152-02); Comment by Diane Geroux (June 17, 2017) (eDocket No. 20176-132944-01); Comment by Judy Kresky (June 20, 2017) (eDocket No. 20176-132944-01); Comment by Jeff Roemer (June 21, 2017) (eDocket No. 20176-133096-01); Comment by Michelle Miller (June 21, 2017) (eDocket No. 20176-133096-01); Comment by Joan Larsen (June 22, 2017) (eDocket No. 20176-133096-01); Comment by Mark Henry (June 29, 2017) (eDocket No. 20176-133339-01); Comment by Cindy Klun (June 29, 2017) (eDocket No. 20176-133339-01); Comment by Greg Nisius (June 29, 2017) (eDocket No. 20176-133339-01); Comment by Bart Martinson (June 29, 2017) (eDocket No. 20176-133339-01); Comment by Brian Dvorak (July 3, 2017) (eDocket No. 20177-133497-01); Comment by Kris Saloum (July 1, 2017) (eDocket No. 20177-133497-01); Comment by Jodie McCullough (June 22, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Karen Holden (June 8, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Anthony Couture (June 7, 2017) (SpeakUp) (eDocket No. 20177-133589-01) Comment by Lane Gabel (June 7, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Terry Pogorels (June 4, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Elizabeth Forsythe (June 2, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Austin Murch (March 24, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Joel Anderson (Jan. 12, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Wayne Lindstrom (Jan. 11, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Richard Paulson (June 29, 2017) (eDocket No. 20177-133656-01); Duluth 2:00 p.m. Tr. 66-68 (June 20, 2017) (Haberman); Duluth 2:00 p.m. Tr. at 87-90 (June 20, 2017) (Topping); Duluth 2:00 p.m. Tr. at 29-34 (June 20, 2017) (Szymialis).

1196 Comment by Judy Budisalovich (June 18, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Rochelle Pearson (June 8, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by David Marklund (June 25, 2017) (eDocket No. 20177-133656-01); Duluth 2:00 p.m. Tr. at 41-44 (June 20, 2017) (Setterlund).

1197 Comment by Robert Hahn (June 20, 2017) (eDocket No. 20176-132944-01); Comment by Marian Clement (June 20, 201) (eDocket No. 20176-132944-01); Comment by Bobbie Jean Mack (June 21, 2017) (eDocket No. 20176-133096-01); Comment by Robert Slimak (June 21, 2017) (eDocket No. 20176-133096-01); Comment by Doris Engman (eDocket No. 20176-133203-01); Comment by Willie Diggs (June 28, 2017) (eDocket No. 20176-133203-01); Comment by Matt Scorich (June 28, 2017) (eDocket No. 20176-133203-01); Comment by Jane Borgren (June 28, 2017) (eDocket No. 20176-133203-01); Comment by Kathleen and Denny Moe (June 29, 2017) (eDocket No. 20176-133339-01); Comment by Robert Topliff (June 29, 2017) (eDocket No. 20176-133339-01); Comment by Jill Christie (June 29, 2017) (eDocket No. 20176-133339-01); Comment by Daniel and Barbara Hoffman (June 29, 2017) (eDocket No. 20176-133339-01); Comment by Bob Kohlmeier (June 29, 2017) (eDocket No. 20176-133339-01); Comment by Mary Louise and Daniel Murphy (June 28, 2017) (eDocket No. 20176-133339-01); Comment by Gordon Nikko (July 3, 2017) (eDocket No. 20177-133497-01); Comment by Eugene Shull (July 1, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Kathleen Moe (June 29, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by John Lenard (June 20, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Howard McKinney (June 5, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Ralph Hammer (June 2, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Larry Voss (May 19, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by LaDonna Swenson (June 20, 2017) (eDocket No. 20177-133656-01); Comment by Dwight Morrison (June 8, 2017) (eDocket No. 20177-133656-01); Comment by Pati Meier (June 15, 2017) (eDocket No. 20177-133656-01); Comment by Dave Sande (June 23, 2017) (eDocket No. 20177-133656-01); Comment by Janet Draper (June 26, 2017) (eDocket No. 20177-133656-01); Comment by Marietta Sutherland (June 23, 2017) (eDocket No. 20177-

5. Sandra and Mathias Justin, residents of Nisswa, dispute the claim that residents in their area pay on average $80.00 per month for electricity, and provided a copy of their electric heating bill showing a charge of $305.00 for the month of November 2016.[1198] The Justins explained that they are on a fixed income and cannot afford a rate increase.[1199]

6. Patricia and James Suchan, residents of Duluth, are a retired couple living in a small home and claim that high energy bills will not allow them to remain in their home for much longer.[1200] The same comment was made by Lillian Zeleznikar, a resident of Duluth.[1201]

7. Dwight Morrison, the vice-president of Citizens Federation Northeast, observed that a high number of low income people live in the Duluth area and will be more heavily impacted by the rate increase.[1202]

C. Multiple Rate Increases

8. A number of individuals claim Minnesota Power has requested too many rate increases during the past few years.[1203]

9. James Gerdes, a resident of Sturgeon Lake, believes Minnesota Power's rate increases should be the equivalent of cost of living raises for people living on social security.[1204]

133656-01); Eveleth 6:30 p.m. Tr. at 26-27 (June 19, 2017) (Dwyer); Duluth 2:00 p.m. Tr. at 47-50 (June 20, 2017) (Pickart); Duluth 2:00 p.m. Tr. at 56-60 (June 20, 2017) (Witt); Duluth 2:00 p.m. Tr. at 68-69 (June 20, 2017) (Challman); Duluth 6:30 p.m. Tr. at 44-49 (June 20, 2017) (Harri); Duluth 6:30 p.m. Tr. at 63-70 (June 20, 2017) (M. Osterman); Duluth 6:30 p.m. Tr. at 70-71 (June 20, 2017) (J. Osterman); Little Falls Tr. at 36-37 (June 22, 2017) (Nouis); Little Falls Tr. at 59-61 (June 22, 2017) (Bruhn).

[1198] Comment by Sandra and Mathias Justin (Dec. 19, 2016) (eDocket No. 20171-127776-01).

[1199] *Id.*

[1200] Comment by Patricia and James Suchan (June 14, 2017) (eDocket No. 20176-132944-01).

[1201] Comment by Lillian Zeleznikar (June 18, 2017) (eDocket No. 20176-132944-01).

[1202] Duluth 2:00 p.m. Tr. at 75-76 (June 20, 2017) (Morrison).

[1203] Comment by Dan Unulock (June 30, 2017) (eDocket No. 20176-133431-01); Comment by Joe Hamilton (June 29, 2017) (eDocket No. 20176-133339-01); Comment by Jeffrey Hammerstrom (June 19, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Carol Kari (June 15, 2017) (eDocket No. 20177-133656-01); Comment by Arnold and Marlene Miller (June 23, 2017) (eDocket No. 20177-133656-01); Duluth 2:00 p.m. Tr. at 60-61 (June 20, 2017) (Lynch); Little Falls Tr. at 57 (June 22, 2017) (Rowan); Comment by Linda Mcintosh (May 31, 2017) (eDocket No. 20176-132653-01).

[1204] Comment by James Gerdes (June 6, 2017) (eDocket No. 20176-132653-01); *see also* Eveleth 6:30 p.m. Tr. at 30-31 (June 19, 2017) (Disterhaft) (small incremental increases are easier to manage).

D. Lack of Competition

10. Some individuals are frustrated by the lack of competition for electric service providers and believe more competition would drive down rates.[1205]

11. Jim Nelson, a resident of Hermantown, believes it is unfair that Minnesota Power is allowed to be a monopoly in the region and if the rate increase is denied, the company will be forced to make difficult decisions and change fund allocations.[1206]

12. Tina Erickson, a resident of Hibbing, commented that it is incumbent upon Minnesota Power to take special care in pricing its services since consumers do not have the option to purchase electricity from another provider.[1207]

E. Energy Conservation

13. Individuals committed to energy conservation ask why the largest users of energy are receiving the lowest rates, contradicting efforts towards energy conservation.[1208] Many individuals are frustrated because they make great efforts to conserve energy but their bills continue to go up because of rate increases.[1209]

14. Charles Mehlberg, a resident of Duluth, claims conservation efforts by residential customers is driving Minnesota Power to raise rates to make up lost revenue.[1210]

F. Renewable Energy Sources

15. Some individuals voiced frustration about rate increases being used to fund renewable energy, which they believe is too expensive.[1211]

[1205] Comment by Frank and Susan Bolos (May 7, 2017) (eDocket No. 20175-132088-01); Comment by Gerard Lawson (June 29, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Carolyn Lofald (June 16, 2017) (SpeakUp) (eDocket No. 20177-133589-01).
[1206] Comment by Jim Nelson (June 29, 2017) (eDocket No. 20176-133339-01).
[1207] Eveleth 2:00 p.m. Tr. at 48-49 (June 19, 2017) (Erickson); *see also* Grand Rapids Tr. at 23 (June 21, 2017) (T. Howg); Grand Rapids Tr. at 24 (June 21, 2017) (R. Howg).
[1208] Comment by Margie Kalligher (June 24, 2017) (eDocket No. 20176-133096-01); Comment by Brian Bergeron (June 29, 2017) (eDocket No. 20176-133339-01); Comment by Kathryn Wegner (June 8, 2017) (eDocket No. 20177-133656-01); Comment by Marcia Fulton (June 8, 2017) (eDocket No. 20177-133656-01); Duluth 2:00 p.m. Tr. at 32-33 (June 20, 2017) (L. Herron).
[1209] Comment by Candace Smolich (June 17, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Chelsea Bartels (June 6, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Bruce Niemi (Jan. 28, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Frederic Hein (Jan. 13, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Janice Hiller (June 21, 2017) (eDocket No. 20177-133656-01); Comment by Jake Wiherski (June 26, 2017) (eDocket No. 20177-133656-01); Grand Rapids Tr. at 30-32 (June 21, 2017) (Tennison).
[1210] Comment by Charles Mehlberg (June 29, 2017) (eDocket No. 20176-133339-01); *see also* Duluth 6:30 p.m. Tr. at 27-29 (June 20, 2017) (St. George).
[1211] Comment by Kenny Bonice (June 22, 2017) (eDocket No. 20176-133096-01); Duluth 6:30 p.m. Tr. at 55-59 (June 20, 2017) (Aagenes).

[102132/1]

16. Other individuals feel Minnesota Power is not pursuing enough renewable energy sources.[1212]

17. Sierra Club members want Minnesota Power's request to extend the fiscal life of the Boswell coal plant to be rejected and support alternative financing mechanisms for phasing out all old coal plants.[1213]

[1212] Comment by Christine Popowski (June 20, 2017) (eDocket No. 20176-133096-01); Duluth 2:00 p.m. Tr. at 31-32 (June 20, 2017) (N. Herron).

[1213] Comment by Karen Renaud (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Jen Bassett (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Joan Christensen (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Ben Effinger (June 29, 2017) (eDocket No. 20176-133398-01); Comment by James Maggi (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Scott Mills (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Bruce Retka (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Kathleen McQuillan (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Edward Shields (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Scott Dulas (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Gian Dodge (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Justin Smith (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Kate Crowley (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Charles Fitze (June 29, 2017) (eDocket No. 20176-133398-01); Comment by John Hinners (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Janice Hasselius (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Howard Lambert (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Ann Miller (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Patricia Hoffmann (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Michael Hadfield (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Michael Trepkowski (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Micky McGilligan (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Mary Madeco-Smith (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Brenda Faber (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Julie Ernst (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Jean Rollin (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Jeffrey Schroeder (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Doreen Koeckeritz (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Nancy Root (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Stephan Aleshire (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Jeffrey Wig (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Christina Nohre (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Bob Beresford (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Bruce and Leane Rutherford (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Jo-Ann Sramek (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Marilyn Gockowski (June 29, 2017) (eDocket No. 20176-133398-01); Comment by George Johnson (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Matthew Butler (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Laura Regan (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Marilyn Borich (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Sharon Powell (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Roxana Allen (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Loretta Neuman (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Sherry Abts (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Molly Gollinger (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Justin Knutson (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Patty Polasky (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Patricia Rasmussen (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Lawrence Landherr (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Dean Borgeson (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Debbie Plese (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Kevin Schwartz (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Julie Owens (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Al Larson (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Lee Waltz (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Ramiro Herrera (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Becky Holum-Brytowski (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Jerry Wambach (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Clarke Dehler (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Linda Dean

18. Diane Langlee, a resident of Hermantown, believes the rate increase is justified by Minnesota Power's investments in renewable energy and aggressive work to meet the state's demands to use renewable sources.[1214] Robert Bassing, a resident of Buhl, agrees that a small rate increase is necessary to cover Minnesota Power's investments in renewable energy.[1215]

19. Mark Skelton, the mayor of Hoyt Lakes, commented that his community is glad to have Minnesota Power as a corporate partner and appreciates the effort put by the company into shifting to renewable energy sources.[1216] Randy Lasky, president of the Northspan Group, and Brian Hanson, a member of Apex, made the same comment.[1217]

G. Corporate Financial Gains

20. Many individuals are troubled by the high level of compensation given to shareholders and executives at Minnesota Power.[1218]

21. William Ralph, a resident of Duluth, believes rate increases fund corporate and shareholder pay raises only.[1219]

22. Arthur Englund, a resident of Pengilly, highlights the fact that Allete Inc., the parent company of Minnesota Power, has a larger than average dividend payout and suggests that the company should put less revenue towards compensating shareholders instead of increasing rates.[1220]

(June 29, 2017) (eDocket No. 20176-133398-01); Comment by Peter Russell (June 29, 2017) (eDocket No. 20176-133398-01); Comment by William Steele (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Monte Gomke (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Jessica Bement (June 29, 2017) (eDocket No. 20176-133398-01); Comment by Rita Clapper (June 29, 2017) (eDocket No. 20176-133398-01); *see also* Comment by Doretta Reisenweber (June 20, 2017) (eDocket No. 20177-133656-01).

[1214] Comment by Diane Langlee (June 23, 2017) (eDocket No. 20177-133656-01); *see also* Comment by LeRoy Bergstrom (June 30, 2017) (eDocket No. 20177-133656-01).

[1215] Eveleth 2:00 p.m. Tr. at 41 (June 19, 2017) (Bassing).

[1216] Eveleth 2:00 p.m. Tr. at 52 (June 19, 2017) (Skelton); *see also* Duluth 2:00 p.m. Tr. at 45-47 (June 20, 2017) (Sundin).

[1217] Duluth 2:00 p.m. Tr. at 36-40 (June 20, 2017) (Lasky); Duluth 2:00 p.m. Tr. at 61-66 (June 20, 2017) (B. Hanson); *see also* Duluth 6:30 p.m. Tr. at 40-44 (June 20, 2017) (Schuettler).

[1218] Comment by Carmelle Latour (Jan. 14, 2017) (eDocket No. 20173-130152-02); Comment by Karen Holden (June 21, 2017) (eDocket No. 20176-133096-01); Comment by Katie Krikorian (June 22, 2017) (eDocket No. 20176-133096-01); Comment by Gerald Marceski (June 24, 2017) (eDocket No. 20176-133096-01); Comment by Brian Bush (March 1, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Dennis Schneider (Jan. 6, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Edward Pocrnich (June 17, 2017) (eDocket No. 20177-133656-01); Comment by William Ralph (Nov. 6, 2016) (eDocket No. 20177-133656-01); Eveleth 2:00 p.m. Tr. at 56-57 (June 19, 2017) (Killien).

[1219] Comment by William Ralph (Nov. 6, 2016) (eDocket No. 20173-130152-02).

[1220] Comment by Arthur Englund (Jan. 27, 2017) (eDocket No. 20173-130152-02); *see also* Comment by Pauline Hassenstab (June 29, 2017) (SpeakUp) (eDocket No. 20177-133589-01).

23. Beth Tamminen, a resident of Duluth and shareholder of Allete Inc., commented that she would rather be treated fairly as a Minnesota Power customer and forgo any increase in her dividend.[1221]

24. Brian Bush, a resident of Duluth, complains that the rate increase is "corporate welfare" because the rate increase subsidizes a for-profit utility company.[1222]

25. On the other hand, Cheryl Stanek, a resident of Little Falls, believes Minnesota Power needs to recover its costs to stay a strong company and provide employees with good compensation and benefits.[1223]

26. Tom Parson, a resident of Cloquet, is a shareholder of Allete Corporation and claims the rate of return currently given to stockholders is adequate but needs to be increased in order for the company to remain competitive.[1224]

27. The International Brotherhood of Electrical Workers Local Union 31 supports the rate increase because potential revenue deficiencies for Minnesota Power will mean reduced wages and benefits for hourly employees who help install and maintain the company's infrastructure on a daily basis.[1225]

28. The United Way of Northeastern Minnesota commented that Minnesota Power received a 2016 leadership award and employees of Minnesota Power commit a great deal of time and money.[1226] The Boys and Girls Clubs of the Northland commented that Minnesota Power is a generous contributor and supporter of the organization.[1227]

29. Carol Anderson, economic development director for Morrison County, commented that Minnesota Power is a good corporate citizen.[1228] Rick Utech, development director for Todd County, made the same comment.[1229]

30. Kent Fredeen, the treasurer of Balkan Township, asked during a public hearing whether the increase in rates is attributable to increased charitable giving by

[1221] Duluth 2:00 p.m. Tr. at 76-70 (June 20, 2017) (Tamminen).
[1222] Comment by Brian Bush (June 28, 2017) (eDocket No. 20176-133203-01); *see also* Comment by Christine Tetzlaff (May 21, 2017) (eDocket No. 20177-133656-01); Eveleth 6:30 p.m. Tr. at 28-29 (June 19, 2017) (Lischalk).
[1223] Comment by Charlie and Cheryl Stanek (June 27, 2017) (eDocket No. 20176-133203-01); *see also* Grand Rapids Tr. at 32-33 (June 21, 2017) (Casio).
[1224] Comment by Tom and Kathy Parson (June 29, 2017) (eDocket No. 20176-133339-01).
[1225] Comment by International Brotherhood of Electrical Workers Local Union 31 (June 30, 2017) (eDocket No. 20177-133497-01); *see also* Eveleth 6:30 p.m. Tr. at 29-30, 32-33 (June 19, 2017) (Keyes, Torma); Duluth 6:30 p.m. Tr. at 39-40 (June 20, 2017) (Marquardt).
[1226] Eveleth 2:00 p.m. Tr. at 34 (June 19, 2017) (Whiting); Duluth 6:30 p.m. Tr. at 37-39 (June 20, 2017) (Hunter); Grand Rapids Tr. at 22-23 (June 21, 2017) (Denucci).
[1227] Duluth 2:00 p.m. Tr. at 44-45 (June 20, 2017) (J. Smith).
[1228] Little Falls Tr. at 31-33 (June 22, 2017) (C. Anderson).
[1229] Little Falls Tr. at 48-50 (June 22, 2017) (Utech).

Minnesota Power.[1230] The answer given was the Commission allows a utility to charge up to 50 percent of charitable giving to ratepayers.[1231]

31. Chad Ronchetti, a resident of Duluth, believes Minnesota Power has played an important leadership role in regional economic development and the rate increases are justified to allow the company to continue their good work.[1232] David Ross, a board member of the Duluth Area Chamber of Commerce, and Bud Stone, the president of the Grand Rapids Area Chamber of Commerce, made the same comment.[1233]

H. Service Quality Issues

32. Some individuals raised service quality concerns. Larry Rude, a resident of Eveleth, complains that the rates keep increasing while Minnesota Power's service has "gone downhill."[1234] Steve Grillo, a resident of Eveleth, has experienced more power outages in the last year than the previous 28 years and thinks Minnesota Power should address the service quality issue before asking for increased rates.[1235]

I. Increases by Customer Class

33. Many individuals believe residential customers are being hit the hardest with rate increases by Minnesota Power and question why commercial and industrial customers are experiencing much lower rate increases.[1236] Residents of the area served by Minnesota Power are not opposed to paying their fair share of utility costs but think it

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[1230] Eveleth 2:00 p.m. Tr. at 42 (June 19, 2017) (Freeden).
[1231] *Id.* at 43.
[1232] Duluth 2:00 p.m. Tr. at 28-30 (June 20, 2017) (Ronchetti).
[1233] Duluth 2:00 p.m. Tr. at 35-36 (June 20, 2017) (Ross); Grand Rapids Tr. at 26-29 (June 21, 2017) (Stone); *see also* Grand Rapids Tr. at 29-30 (June 21, 2017) (Sackett).
[1234] Comment by Larry Rude (June 21, 2017) (eDocket No. 20176-133096-01).
[1235] Comment by Steve Grillo (Jan. 29, 2017) (SpeakUp) (eDocket No. 20177-133589-01); *see also* Comment by Kim Louks (Jan. 9, 2017) (SpeakUp) (eDocket No. 20177-133589-01).
[1236] Comment by Susan Schwanekamp (June 29, 2017) (eDocket No. 20176-133339-01); Comment by Jasmine Phoenix (June 29, 2017) (eDocket No. 20176-133339-01); Comment by Lloyd Schallberg (July 3, 2017) (eDocket No. 20177-133497-01); Comment by Jill Jacoby (July 3, 2017) (eDocket No. 20177-133497-01); Comment by Marlene Miller (July 2, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Molly Thompson (June 29, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Peg Mold (June 29, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Daniel Ralidak (June 28, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Harold Martin (June 21, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Elizabeth Blue (June 16, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Steven Schmidt (June 14, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Richard Harri (June 7, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Catherine Gorghuber (June 2, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Linda McIntosh (May 31, 2017) (eDocket No. 20177-133656-01); Comment by Audrey Devine Eller (May 31, 2017) (eDocket No. 20177-133656-01); Comment by Brenda Gilbert Anderson (June 20, 2017) (eDocket No. 20177-133656-01); Comment by John and Sally Maki (June 8, 2017) (eDocket No. 20177-133656-01); Comment by Linda Corbin (July 2, 2017) (eDocket No. 20177-133656-01); Comment by Damon Anderson (June 21, 2017) (eDocket No. 20177-133656-01); Comment by Susan Nordin (June 30, 2017) (eDocket No. 20177-133656-01); Eveleth 2:00 p.m. Tr. at 46 (June 19, 2017) (Lampinen); Duluth 2:00 p.m. Tr. at 51-56 (June 20, 2017) (Robinson); Little Falls Tr. at 33-35 (June 22, 2017) (Martin); Little Falls Tr. at 61-63 (June 22, 2017) (Meyer).

is unfair for them to receive rate increases three times greater than commercial and industrial customers. [1237]

[1237] Comment by Michael Barten (May 16, 2017) (eDocket No. 20175-132088-01); Comment by Ronald Meyer (May 16, 2017) (eDocket No. 20175-132088-01); Comment by Karen Germ (May 16, 2017) (eDocket No. 20175-132088-01); Comment by Richard Thouin (May 16, 2017) (eDocket No. 20175-132088-01); Comment by Barbara Degerstedt (May 16, 2017) (eDocket No. 20175-132088-01); Comment by Frederick Husom (May 17, 2017) (eDocket No. 20175-132088-01); Comment by Wesley Sisson (May 17, 2017) (eDocket No. 20175-132088-01); Sandra Poppenberg (May 19, 2017) (eDocket No. 20175-132088-01); Comment by M. Staffaroni (May 22, 2017) (eDocket No. 20176-132653-01); Comment by Don Werdick (May 23, 2017) (eDocket No. 20176-132653-01); Comment by Donna Werdick (May 23, 2017) (eDocket No. 20176-132653-01); Comment by Uldis Birznieks (May 31, 2017) (eDocket No. 20176-132653-01); Comment by Frank Heller (June 8, 2017) (eDocket No. 20176-132761-01); Comment by Brian Bush (June 9, 2017) (eDocket No. 20176-132761-01); Comment by Bryce Nixon (June 9, 2017) (eDocket No. 20176-132761-01); Comment by Michael Melby (June 9, 2017) (eDocket No. 20176-132761-01); Comment by Barbara Henry (June 9, 2017) (eDocket No. 20176-132761-01); Comment by Lawrie Truman (June 11, 2017) (eDocket No. 20176-132761-01); Comment by Kathy Sowl (June 14, 2017) (eDocket No. 20176-132944-01); Comment by Merlin Crosby (June 15, 2017) (eDocket No. 20176-132944-01); Comment by Terri Hayes (June 15, 2017) (eDocket No. 20176-132944-01); Comment by James Bertucci (June 16, 2017) (eDocket No. 20176-132944-01); Comment by Jessica Worden (June 16, 2017) (eDocket No. 20176-132944-01); Comment by Chad Parks (June 17, 2017) (eDocket No. 20176-132944-01); Gloria and Leif Brush (June 17, 2017) (eDocket No. 21076-132944-01); Comment by Howard McKinney (June 18, 2017) (eDocket No. 21076-132944-01); Comment by Jeanette Jobin (June 18, 2017) (eDocket No. 21076-132944-01); Comment by Ruth McCutcheon (June 19, 2017) (eDocket No. 21076-132944-01); Comment by Cindy Mattson (June 19, 2017) (eDocket No. 21076-132944-01); Comment by Dennis Thielen (June 20, 2017) (eDocket No. 20176-132944-01); Comment by Gloria Sorenson (June 20, 2017) (eDocket No. 20176-132944-01); Comment by Arlene Kelley (June 20, 2017) (eDocket No. 20176-132944-01); Comment by Harry Eliason (June 20, 2017) (eDocket No. 20176-132944-01); Comment by Carol Uecker (June 20, 2017) (eDocket No. 20176-132944-01); Comment by Pam Hendrickson (June 21, 2017) (eDocket No. 20176-133096-01); Comment by David Walker (June 21, 2017) (eDocket No. 20176-133096-01) Comment by Debbie Ortman (June 22, 2017) (eDocket No. 20176-133096-01); Comment by Patricia Castellano (June 23, 2017) (eDocket No. 20176-133096-01); Comment by Keith Welshinger (June 23, 2017) (eDocket No. 20176-133096-01); Comment by Lauri Smith (June 23, 2017) (eDocket No. 20176-133096-01); Comment by Grace Bennett (June 24, 2017) (eDocket No. 20176-133096-01); Comment by Deborah Hendrickson (June 24, 2017) (eDocket No. 20176-133096-01); Comment by Beverly Rowland (June 26, 2017) (eDocket No. 20176-133203-01); Comment by Susan Kyllonen (June 27, 2017) (eDocket No. 20176-133203-01); Comment by Kristi Nelson (June 27, 2017) (eDocket No. 20176-133203-01); Comment by Kristina Buckanaga (June 27, 2017) (eDocket No. 20176-133203-01); Comment by Mike Hamski (June 27, 2017) (eDocket No. 20176-133203-01); Comment by Christie Gingles (June 28, 2017) (eDocket No. 20176-133203-01); Comment by Carol and Jerrold Peterson (June 28, 2017) (eDocket No. 20176-133203-01); Comment by Jo Paull (June 28, 2017) (eDocket No. 20176-133203-01); Comment by Brenda Stokke (June 28, 2017) (eDocket No. 20176-133203-01); Comment by Kim Luedtke (June 28, 2017) (eDocket No. 20176-133203-01); Comment by Jim Boyd (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Kim Buncich (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Robert Calhoun (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Andrew Anderson (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Kurt Hannula (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Ruth Handberg (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Brenda Goodreau (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Cheryl Ekstrand (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Patricia Curtis (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Tracey Craven (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Belinda Coley (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Chris Cigalio (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Suzanne Chesney (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Tisha Cadotte (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Sharon Buchanan (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Terry Bronniche (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Tyler Bosiacki (June 28, 2017) (eDocket No. 20176-133431-

01); Comment by Ruby Berg (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Suzanne Anderson (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Libby Anderson (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Amanda Anderson (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Kathleen Adee (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Mark Loushin (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Scott Walker (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Nancy Otos (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Beth Hohenstein (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Peggy Senarighi (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Tim Sandack (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Thor Eggen (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Kimberly McIntyre (June 28, 2017) (eDocket No. 20176-133431-01); Comment by Theresa Flesvig (June 28, 2017) (eDocket No. 20176-133431-01); 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Comment by Robert Slimak (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Anne Sarvela (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Jeanne Rychlak (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Chris Rollins (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Elizabeth Peterson (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Roberta Pascuzzi (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Cathy Overland (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Valerie Ouellette (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Pat Osterberg (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Sarah Nunn (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Rachel Newman (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Lori Nelson (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Heidi Nelson (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Blake Nelson (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Michael Napoli (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Linda McDonald (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Gerald Marceski (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Mike Lelanc (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Michael LeBlanc (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Mia Lawson (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Carol King (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Molly Johnson (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Doug Jensen (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Jill Jacoby (June 30, 2017) (eDocket No. 20176-133426-01); Comment by WyAnn Hulst-Perry (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Rose Hoene (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Rozena Higgins (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Kristiane Harder (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Tracey Hanson (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Marcia Hanson (June 30,

2017) (eDocket No. 20176-133426-01); Comment by James Hoff (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Natasha Wyland (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Jim Mattson (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Katelyn Starkey (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Aana Butler (June 30, 2017) (eDocket No. 20176-133426-01); Comment by Elizabeth Mettser (June 30, 2017) (eDocket No. 20176-133425-01); Comment by John Banstorf (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Karla and Robb Winterfeld (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Virginia Voseko (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Joseph Zimmerman (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Troy Kobes (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Judy Dahl (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Tayler Schoenberg (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Mary Herbertz (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Cheryl Whereatt (June 30, 2017) (eDocket No. 20176-133425-01); Karley Schoenberg (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Anna Kellerhuis (June 30, 2017) (eDocket No. 20176-133425-01); Comment by James Hencinski (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Susan Hencinski (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Greg Cooper (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Anthony Olson (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Lorelei Livesay (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Jim Livesay (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Sue Mageau (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Crystal Carlson (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Mary Morei (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Roger Boberg (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Dorothy Conrad (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Heather Bashaw (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Brenda Pfab (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Lois Nylen (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Sherri Boisjoli (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Diana Hawks (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Chim Nguyen (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Ron Patsche (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Ahnon Kennedy (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Tim Holleran (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Peggy Spehan (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Sarah Herried (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Taylor Leyner (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Betty Kingsley (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Thomas Spehar (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Monica Scheflo (June 30, 2017) (eDocket No. 20176-133425-01); Marshall Hampton (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Julie Soderberg (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Erin Metzger (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Erik Pavelka (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Phyllis Matila (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Brian Pfeifer (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Jon Downing (June 30, 2017) (eDocket No. 20176-133425-01); Comment by Marsha Griffin (June 29, 2017) (eDocket No. 20176-133339-01); Comment by Brooke Pekkala (June 28, 2017) (eDocket No. 20176-133339-01); Comment by Donna Beaupre (June 28, 2017) (eDocket No. 20176-133339-01); Comment by Marilee Bodie (June 28, 2017) (eDocket No. 20176-133339-01); Comment by Kimberly Groehler (June 28, 2017) (eDocket No. 20176-133339-01); Comment by Amanda Borgren (June 28, 2017) (eDocket No. 20176-133339-01); Comment by Jim Unden (June 28, 2017) (eDocket No. 20176-133339-01); Comment by Terrie Barse (July 5, 2017) (eDocket No. 20177-133497-01); Comment by JoAnn Nyberg (July 5, 2017) (eDocket No. 20177-133497-01); Comment by Lowana Greensky (July 5, 2017) (eDocket No. 20177-133497-01); Comment by Barry Daoust (July 5, 2017) (eDocket No. 20177-133497-01); Comment by Arika Stanley (July 5, 2017) (eDocket No. 20177-133497-01); Comment by Scott Braith (July 5, 2017) (eDocket No. 20177-133497-01); Comment by Mary Lee (July 5, 2017) (eDocket No. 20177-133497-01); Comment by Gloria Gelkeg (July 5, 2017) (eDocket No. 20177-133497-01); Comment by David Brown (July 5, 2017) (eDocket No. 20177-133497-01); Comment by Regina Berger (July 5, 2017) (eDocket No. 20177-133497-01); Comment by Jane Akkanen (July 5, 2017) (eDocket No. 20177-133497-01); Comment by Judy Mardich (July 5, 2017) (eDocket No. 20177-133497-01); Comment by LeRoy Mardich (July 5, 2017) (eDocket No. 20177-133497-01); Comment by Nancy York (July 5, 2017) (eDocket No. 20177-133497-01); Comment by Mike Miller (July 5, 2017) (eDocket No. 20177-133497-01); Brook Warren (July 5, 2017) (eDocket No. 20177-133497-

34. John Goodge, a resident of Duluth, believes all customers should pay the same rate so fees scale linearly with consumption.[1238]

35. Joel Sipress, a member of the Duluth Public Utilities Commission, believes the rate structure needs to be maintained in a way that limits the impact on small users as opposed to punishing small users of electricity.[1239]

36. Tom Tusken, a teacher at Denfeld High School, believes Minnesota Power is a good company but objects to the company asking residential consumers to subsidize the mining industry by paying higher rates.[1240]

37. Save Our Sky Blue Waters, a nonprofit organization representing interests in the Arrowhead Region, believes that a rate increase for residential customers will contribute to additional economic hardship in an already depressed economy in many parts of northeastern Minnesota.[1241] The organization asserts that residential customers should not be penalized for Minnesota Power's decision to increase energy capacity based upon future industrial power projections.[1242]

38. Guy Priley, a resident of Duluth and employee at a local paper mill, believes low rates for energy are critical to the sustainability of his company in the global marketplace and points out that if his company goes out of business, Minnesota Power will have to make up the loss of revenue by charging ratepayers in the community even higher rates.[1243]

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01); Comment by Gloria Seveng (July 5, 2017) (eDocket No. 20177-133497-01); Comment by Pat McCanon (July 5, 2017) (eDocket No. 20177-133497-01); Comment by Jeanne Wahlstrom (July 5, 2017) (eDocket No. 20177-133497-01); Comment by Gerald Piekkola (July 5, 2017) (eDocket No. 20177-133497-01); Comment by Debra Caillouette (July 5, 2017) (eDocket No. 20177-133497-01); Comment by Penny Jebbitt (July 5, 2017) (eDocket No. 20177-133497-01); Comment by Robert Cass (July 5, 2017) (eDocket No. 20177-133497-01); Comment by Sarah Cone (July 5, 2017) (eDocket No. 20177-133497-01); Comment by Angie Parks (July 5, 2017) (eDocket No. 20177-133497-01); Comment by Karen Finke (July 5, 2017) (eDocket No. 20177-133497-01); Comment by Tracy Schwartz (July 5, 2017) (eDocket No. 20177-133497-01); Comment by Sandy Dwyer (July 5, 2017) (eDocket No. 20177-133497-01).

[1238] Comment by John Goodge (June 30, 2017) (eDocket No. 20176-133339-01).

[1239] Duluth 2:00 p.m. Tr. at 69-75 (June 20, 2017) (Sipress).

[1240] Comment by Tom Tusken (June 29, 2017) (eDocket No. 20176-133339-01); *see also* Comment by Glenn Peterson (July 2, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Brook Johnson (June 29, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Diane Desotelle (June 20, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Thomas Nikko (June 16, 2017) (SpeakUp) (eDocket No. 20177-133589-01); Comment by Diana Conway (June 3, 2017) (SpeakUp) (eDocket No. 20177-133589-01).

[1241] Comment by Save Our Sky Blue Waters (June 30, 2017) (eDocket No. 20177-133497-01).

[1242] *Id.*

[1243] Duluth 2:00 p.m. Tr. at 80-82 (June 20, 2017) (Priley); *see also* Duluth 2:00 p.m. Tr. at 82-83 (June 20, 2017) (Dodson); Duluth 6:30 p.m. Tr. at 34-37 (June 20, 2017) (M. Carlson); Duluth 6:30 p.m. Tr. at 49-50 (June 20, 2017) (Stolan).

39. Kelsey Johnson, the president of the Mining Association of Minnesota, says the mining industry can no longer afford to subsidize the rates of other energy users in the state while remaining competitive in the global economy.[1244]

J. Infrastructure

40. David Updegraff, a citizen of Duluth, supports the portion of the rate increased to be used on infrastructure improvements.[1245]

41. Becky Holum-Brytowski, a resident of Princeton, believes residential customers should not be paying higher rates to fund the power industry's infrastructure updates for renewable energy.[1246] Ms. Holum-Brytowski noted that paying higher utility bills means her family cannot afford to transition to energy saving appliances in their home.[1247]

[1244] Duluth 6:30 p.m. Tr. at 59-63 (June 20, 2017) (K. Johnson); *see also* Grand Rapids Tr. at 25-26 (June 21, 2017) (Koerbitz).
[1245] Comment by David Updegraff (June 30, 2017) (SpeakUp) (eDocket No. 20177-133589-01).
[1246] Comment by Becky Holum-Brytowski (June 16, 2017) (eDocket No. 20176-132944-01).
[1247] *Id.*

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November 7, 2017

To:
Public Utilities Commission
121 Seventh Pl E Ste 350
St. Paul, MN 55101

and the parties to this case

Re: In the Matter of the Application by Minnesota Power for Authority to Increase Rates for Electric Services in Minnesota

OAH 5-2500-34078
MPUC E-015/GR-16-664

Enclosed and served upon you is the Administrative Law Judge's **FINDINGS OF FACT, CONCLUSIONS OF LAW AND RECOMMENDATIONS** in the above-entitled matter.

This report is written in the format of a typical contested case report. That is, the structure is built of findings of fact, conclusions of law, the recommendations, and a memorandum explaining my rationale for all of those elements. This style is not often used for rate case reports because of the volume of information that must be addressed. However, to aid the reader, I recommend relying on the table of contents to easily move between a particular topic in the findings of fact to the conclusions of law and to the memorandum. In fact, if you read the report on a computer, the table of contents includes bookmarks that permit the reader to press CTRL and left click the topic line and you will be brought to that place in the report. Returning to the table of contents is relatively easy from the middle of the report so you can move through each sub-issue without reading through, for example, all the findings of fact before proceeding to all of the conclusions of law, and so forth.

If you have any questions, please contact my legal assistant Sheena Denny at (651) 361-7881 or Sheena.Denny@state.mn.us, or facsimile at (651) 539-0310.

Sincerely,

JIM MORTENSON
Administrative Law Judge

JRM:sd
Enclosure

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600 NORTH ROBERT STREET
ST. PAUL, MINNESOTA 55164

CERTIFICATE OF SERVICE

In the Matter of the Application by Minnesota Power for Authority to Increase Rates for Electric Services in Minnesota	OAH Docket No.: 5-2500-34078 E-015/GR-16-664

Sheena Denny, certifies that on November 7, 2017 she served the true and correct **FINDINGS OF FACT, CONCLUSIONS OF LAW AND RECOMMENDATIONS** by eService, and U.S. Mail, (in the manner indicated below) to the following individuals:

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